# MANAGEMENT DISCUSSION AND ANALYSIS

SUMMARY OF FINANCIAL AI	ND OPERATIO	NAL RESUL	.TS			
	Three M	onths Ended De	ecember 31		Year Ended D	ecember 31
	2011	2010	% Change	2011	2010	% Change
FINANCIAL						
Oil and gas revenue	19,089,409	11,250,143	70	58,465,937	43,665,720	34
Funds from operations <sup>1</sup>	8,440,515	5,041,937	67	29,273,892	17,872,490	64
Per share - basic	0.05	0.04	25	0.18	0.13	38
-diluted	0.05	0.04	25	0.18	0.13	39
Net loss	(4,051,189)	(6,443,517)	(37)	(2,545,214)	(6,291,319)	(60)
Per share - basic	(0.03)	(0.05)	100	(0.02)	(0.05)	(66)
-diluted	(0.03)	(0.05)	100	(0.02)	(0.05)	(66)
Total debt	55,751,531	18,787,775	197	55,751,531	18,787,775	197
Capital expenditures	13,578,475	12,858,003	6	40,470,999	25,956,140	56
Property acquisitions	38,574,702	2,184,049	1,666	38,574,702	2,259,529	1,607
Property dispositions	-	-	-	(621,914)	(5,919,077)	(89)
Wells drilled (net)						
Oil	1.40	6.23	(78)	6.02	8.51	(29)
Gas	-	1.00	-	-	1.00	-
Dry	-	3.00	-	3.00	3.00	-
Total net wells drilled	1.40	10.23	(86)	9.02	12.51	(28)
Shares outstanding - end of period	157,282,261	140,812,472	12	157,282,261	140,812,472	12
OPERATIONAL						
Daily production						
Heavy oil (bbl/d)	124	202	(39)	170	252	(33)
Light oil and NGLs (bbl/d)	2,082	1,408	48	1,654	1,336	24
Natural gas (mcf/d)	4,158	3,131	33	2,439	3,032	(20)
Oil equivalent (boe @ 6:1) <sup>2</sup>	2,899	2,132	36	2,230	2,093	7
Realized commodity prices (\$Cdn.)						
Heavy oil (bbl)	81.85	60.34	36	70.84	61.92	14
Light oil and NGLs (bbl)	88.93	70.99	25	84.47	69.03	22
Natural gas (mcf)	2.93	3.23	(9)	3.47	3.91	(11)
Oil equivalent (boe @ 6:1)	71.57	57.34	25	71.82	57.17	26
Operating netback (\$ per boe)						
Revenue	71.57	57.34	25	71.82	57.17	26
Royalty	(15.58)	(9.95)	57	(14.47)	(10.25)	41
Operating cost	(18.44)	(17.37)	6	(17.86)	(18.94)	(6)
Transportation cost	(0.75)	(1.15)	(35)	(1.59)	(1.07)	48
Operating netback per boe	36.80	28.88	27	37.91	26.91	41
General and administrative	(2.80)	(3.57)	(21)	(4.88)	(4.59)	6
Finance expenses	(1.43)	(0.83)	73	(1.15)	(1.34)	(14)
Other	0.38	(0.15)	359	(0.05)	0.07	(170)
Realized hedging gains (losses)	(1.30)	1.36	(196)	4.12	2.34	76
Funds flow per Boe	31.65	25.70	23	35.95	23.40	54

(1) "Funds from operations", "funds from operations per share", "netbacks" and "netbacks per boe" are not defined by International Financial Reporting Standards ("IFRS") and are regarded as non-GAAP measures. Funds from operations and funds from operations per share are calculated as cash provided by operating activities before changes in non-cash working capital, decommissioning obligations settled and seismic expenses. Funds from operations is used to analyze the Company's operating performance, the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations does not have a standardized measure prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other companies. The Company also presents funds from operation per share whereby per share amounts are calculated using the weighted average number of common shares outstanding consistent with the calculation of net income or loss per share.

(2) The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel (6 mcf/bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the report are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil.

### 2011 Financial and Operational Highlights

In November 2011, Arsenal announced the closing of a strategic acquisition of oil and gas properties in its core oil producing areas of Alberta for \$38.6 million subject to normal property acquisition closing adjustments. The acquisition added approximately 1,500 Boe per day of production split evenly between medium gravity oil and natural gas. Total reserves added from this property acquisition at December 31, 2011 were 2.4 million Boe of proved reserves and 3.6 million Boe of proved plus probable reserves.

As a result of the acquisition and operations conducted in Q3 and Q4 of 2011, the Company's syndicated credit facility was increased to \$75 million.

In 2011, the Company recorded increased quarterly revenues of \$11.6 million in Q1, \$12.8 million in Q2, \$15.0 million in Q3 and \$19.1 million in Q4 due to production increases in North Dakota, solid commodity prices and the Q4 2011 property acquisition.

Due largely to the drilling of Company operated North Dakota Bakken wells at Stanley, US production increased in 2011 from 671 Boe per day in Q1 2011 to 1,077 Boe per day in Q4 2011. Production from the Bakken formation is sweet light oil with a high operating netback.

In August 2011, the Company monetized all of its existing commodity contracts generating cash proceeds and a realized gain of \$4.5 million.

For Q4 2011, the Company's operating netback per Boe (revenues less royalties, operating and transportation expenses) increased 27% to \$36.80 per Boe from \$28.88 in Q4 2010.

Funds from operations (after realized commodity contract gains/losses) for Q4 2011 totaled \$8.4 million or \$0.05 per share basic and diluted compared to \$5.0 million or \$0.04 per share basic and diluted in Q4 2010. For 2011, funds from operations totaled \$29.3 million or \$0.18 per share basic and diluted compared to \$17.9 million or \$0.13 per share basic and diluted in 2010.

Cash netback per Boe (funds from operations per Boe) in Q4 2011 increased 23% to \$31.65 per Boe from \$25.70 in Q4 2010. The Q4 2011 increase is due to higher average production, a higher operating margin per Boe (due primarily to higher commodity prices), lower general and administrative expenses per Boe and a foreign exchange gain offset by losses realized in the quarter on commodity contracts. For 2011, cash netback per Boe increased by 54% from \$23.40 per Boe in 2010 to \$35.96 per Boe for 2011. A higher operating margin per Boe (due primarily to higher commodity prices) and higher realized gains in 2011 on commodity contracts were major factors contributing to this increase.

Total debt at December 31, 2011 was \$55.8 million, up from \$9.2 million at September 30, 2011 and up from \$18.8 million at December 31, 2010 due to the late 2011 property acquisition of \$38.6 million. The Company's debt fluctuated somewhat in 2011 due to an equity financing in February 2011 that generated net proceeds of \$19.4 million, the monetization of the Company's commodity contracts in Q3 2011 for \$4.5 million and the increase in

Q4 2011 due to the property acquisition. Capital expenditures on property, plant and equipment and exploration and evaluation expenses during the year totaled \$40.5 million. These expenditures exceeded cash generated from operations by \$11.0.

Arsenal's production for Q4 2011 averaged 2,899 Boe per day (76% crude oil and NGL's and 24% natural gas) versus a Q3 2011 average of 2,185 Boe per day (88% crude oil and NGL's and 12% natural gas) and a Q4 2010 average of 2,132 Boe per day (76% crude oil and NGL's and 24% natural gas).

For 2011, production averaged 2,230 Boe per day (82% crude oil and NGL's and 18% natural gas) a 7% increase from 2,093 Boe per day (76% crude oil and NGL's and 24% natural gas) in 2010.

Capital expenditures in 2011 totaled \$40.5 million versus \$26.0 million for 2010. Capital expenditures in Canada were used to drill at Evi, Chauvin, Provost and Edgerton, to purchase land at Princess and Columbia, to construct facilities at Princess and to shoot and purchase seismic at Edgerton, Provost and Princess. In the US, capital was expended to drill and/or complete three Bakken wells and to purchase additional land. In addition, in 2011, the Company spent \$38.6 million on an acquisition and disposed of three non-core property for proceeds of \$621,914.

On June 16, 2011, the Company announced its intention to make a normal course issuer bid ("NCIB") that commenced June 20, 2011 and ends June 19, 2012. A total of 8,128,724 common shares may be acquired under the bid representing 5% of the common shares outstanding as of June 14, 2011. To March 21, 2012, the Company has purchased 6,510,044 common shares at an average cost of \$0.65 per share plus expenses under this bid.

As of March 21, 2012, Arsenal has 158,466,062 common shares and 14,693,670 stock options outstanding. The Company's shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "AEI" and in the US on the pink sheets under the symbol AEYIF.PK.

In Canada, the Company operates under Arsenal Energy Inc. Production in Canada averaged 1,822 Boe per day for Q4 2011. In the US, the Company operates under its 100% owned subsidiary Arsenal Energy USA Inc. Production from the US averaged 1,077 Boe per day for Q4 2011.

#### **Basis of Presentation**

The following is management's discussion and analysis ("MD&A") of Arsenal Energy Inc.'s ("Arsenal" or the "Company") audited operating and financial results for the year ended December 31, 2011. It should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the year ended December 31, 2011 and other operating and financial information contained herein and in conjunction with the Annual Information Form ("AIF") for the year ended December 31, 2011 which includes reserves information prepared in accordance with National Instrument 51 - 101 - Standards of Disclosure for Oil and Gas Activities. This MD&A is dated March 21, 2011.

The consolidated financial statements and comparative information has been prepared in accordance with International Financial Reporting Standards ("IFRS"). Previously the Company prepared its annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These previously reported consolidated financial statements were adjusted to be in compliance with IFRS on January 1, 2010, the "transition date". Previously reported results and balances subsequent to the date of adoption on January 1, 2011 have been restated to IFRS. The adoption of IFRS has not had a material impact on the Company's operations, strategic decisions or funds flow from operations before changes in non-cash working capital. The significant accounting policies used by the Company are outlined in the Company's consolidated financial statements for the years ended December 31, 2011 and 2010.

Unless otherwise specified, all dollar amounts are stated in Canadian dollars, and all references to "dollars" or "\$" are to Canadian dollars.

Tables may not add due to rounding.

Certain prior period amounts have been reclassified to conform to the current period's presentation.

Additional information regarding Arsenal's AIF, financial and operating results may be obtained on the internet at www.sedar.com.

#### **Forward-Looking Statements**

Certain statements contained within the Management's Discussion and Analysis, constitute forward looking statements. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as 'seek', 'anticipate', 'budget', 'plan', 'continue', 'estimate', 'expect', 'forecast', 'may', 'will', 'propose', 'project', 'predict', 'potential', 'targeting', 'intend', 'could', 'might', 'should', 'believe' and similar expressions or the negative of these terms or other comparable terminology and are generally intended to identify forward looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward looking statements.

In particular, this MD&A contains the following forward-looking statements pertaining to, without limitation, the following: Arsenal's production volumes and the timing of when additional production volumes will come on stream; Arsenal's realized price of commodities in relation to reference prices; future commodity prices; the Company's future royalty rates and the realization of royalty incentives; the impact of the New Royalty Framework on the Company's future royalties; Arsenal's expectation of reducing operating costs on a per unit basis; the relationship of Arsenal's interest expense and the Bank of Canada interest rates; increases in general and administrative expenses and recoveries; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected decrease in the depletion, depreciation and accretion rate; the estimated future contractual obligations of the Company and the amount expected to be incurred under its farm-in commitments; the future liquidity and financial capacity of the Company; and its ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to 'reserves' or 'resources' are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

With respect to the forward-looking statements contained in the MD&A, Arsenal has made assumptions regarding: future commodity prices; the impact of royalty regimes and certain royalty incentives, the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on-stream; future proved finding and development costs; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continuation of the current tax and regulation. We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in this MD&A: volatility in market prices for oil and natural gas; counterparty credit risk; access to

capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of Arsenal stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under "Risk Factors" in the following annual MD&A. Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website. The forward looking statements contained in this MD&A are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Arsenal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

#### **Boe Presentation**

For the purpose of calculating unit costs, natural gas is converted to barrel of oil equivalent ("Boe" or "boe") using six thousand cubic feet ("Mcf") of natural gas to one barrel of oil equivalent unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel of oil equivalent is based on an energy equivalency method primarily at the burner tip and does not represent a value equivalency at the wellhead. (This conversion conforms to National Instrument 51-101). References to natural gas liquids ("NGLs") in this MD&A include condensate, propane, butane and ethane and one barrel of NGLs is considered to be equivalent to one barrel of crude oil equivalent (Boe).

#### **Non-GAAP Measurements**

Within the MD&A, references are made to terms having widespread use in the oil and gas industry in Canada. The measures discussed are widely accepted measures of performance and value within the industry, and are used by investors and analysts to compare and evaluate oil and gas exploration and producing entities.

"Funds from operations", "Funds from operations per share", "Operating netbacks per unit or per Boe", "Netbacks per unit or per Boe", "Net debt", "Total debt" or "Bank debt" are not defined by IFRS in Canada and are regarded as non-GAAP measures.

Operating (or field) netback equals total revenue less royalties and operating costs (that include transportation) calculated on a commodity and Boe basis. Boe production per day is calculated by dividing total production for the year or quarter by the number of days in the year or quarter as the case may be. Funds from operation netback is operating netback plus or minus realized gains or losses on commodity contracts and foreign exchange transactions less cash expenses for general and administrative, interest and other financing charges and other cash expenses calculated on a Boe basis.

Total debt is defined as bank borrowings plus working capital (excess or deficiency) and excludes decommissioning obligations and the value of risk management contracts whether short or long term and whether an asset or an obligation.

### **Funds from Operations**

Funds from operations are not recognized by IFRS but it is used by investors, analysts, bankers and others to evaluate and compare oil and gas exploration and producing entities. The Company's banker uses funds from operations to measure debt to funds flow ratios that determine interest costs to the Company under its credit facility.

Funds from operations are determined by cash flow from operations before the change in non-cash operating working capital, seismic expenses and decommissioning obligations settled. The Company's banker uses funds from operations (adjusted for the above and for interest and other financing charges) to measure debt to funds flow ratios that determine interest costs to the Company under its credit facility. Funds from operations are used to analyze the Company's performance, the ability of the business to generate the cash flow necessary to fund growth through capital investment and to repay bank debt. Funds from operations should not be considered as an alternative to, or more meaningful than cash provided from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. Funds from operations per share basic is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share. Funds from operations per diluted share are calculated based on the weighted average number of common shares outstanding adjusted for dilutive instruments which in Arsenal's case are only stock options.

The following tables compare cash provided by operating activities to funds from operations, funds from operations by country and funds from operations netback per Boe for Q4 2011 to Q4 2010 and for the year ended December 31, 2011 to the year ended December 31, 2010. These numbers are referred to in the MD&A:

Funds from Operations	Three Mo	onths Ended D	ecember 31		Year Ended December			
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change		
Cash provided by operating activities	2,872,022	5,358,828	(46)	25,301,234	11,082,654	128		
Seismic expenses	793,443	53,900	1,372	1,555,130	1,663,037	(6)		
Decommissioning obligations settled	311,396	90,174	245	819,283	1,083,838	(24)		
Change in non-cash working capital	4,463,654	(460,965)	(1,068)	1,598,245	4,042,961	(60)		
Funds from operations	8,440,515	5,041,937	67	29,273,892	17,872,490	64		

Funds From Operations By Country	Three Mo	onths Ended D	December 31		Year Ended December			
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change		
Canada	3,955,202	2,980,599	33	16,251,620	11,366,791	43		
US	4,485,313	2,061,338	118	13,022,272	6,505,699	100		
Funds from operations	8,440,515	5,041,937	67	29,273,892	17,872,490	64		

Funds From Operations Netback per Boe	Three Months Ended December 31 Year Ended Decem					
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada	23.59	23.53	0	31.60	21.50	47
US	45.28	29.65	53	43.45	27.68	57
Total	31.65	25.70	23	35.96	23.40	54

For 2011, funds from operations totaled \$29.3 million or \$35.96 per Boe versus \$17.9 million or \$23.40 per Boe in 2010. The operating netback in 2011 was \$36.80 per Boe versus \$28.88 per Boe in 2010 (average Boe prices increased in 2011 by 26%). The funds from operations netback in 2011 includes \$3.4 million or \$4.12 per Boe related to the monetization of commodity contracts versus \$1.8 million or \$2.34 per Boe in 2010.

The following tables show quarterly production and compares funds from operations by country and funds from operations and funds from operations per Boe both before and after the effect of commodity contracts for the past eight quarters.

Production		<b>2011</b> 2010						
(Boe's)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Canada	1,822	1,235	1,245	1,331	1,376	1,371	1,379	1,673
US	1,077	950	581	671	756	655	681	481
Total	2,899	2,185	1,826	2,002	2,132	2,026	2,060	2,154

Funds From Operations By Country		201	.1		2010				
(\$Cdn.)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	
Canada	3,955,202	6,285,005	2,684,082	3,327,331	2,980,599	2,167,109	2,152,748	4,066,335	
US	4,485,313	5,140,970	1,617,685	1,778,304	2,061,338	1,466,603	1,854,690	1,123,068	
After commodity contracts	8,440,515	11,425,975	4,301,767	5,105,635	5,041,937	3,633,712	4,007,438	5,189,403	

Funds From Operations		201	.1		2010				
(\$Cdn.)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	
Before commodity contracts	8,787,470	6,950,756	4,802,027	5,376,646	4,774,814	2,987,571	3,450,436	4,871,045	
Effect of realized comodity contracts	(346,955)	4,475,219	(500,260)	(271,011)	267,123	646,141	557,002	318,358	
After commodity contracts	8,440,515	11,425,975	4,301,767	5,105,635	5,041,937	3,633,712	4,007,438	5,189,403	

Funds From Operations Per Boe		<b>2011</b> 2010						
(\$Cdn.)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Before commodity contracts	32.95	34.58	28.90	29.84	24.34	16.03	18.41	25.13
After commodity contracts	31.65	56.85	25.89	28.34	25.70	19.50	21.38	26.77

The increases and decreases in the above periods relate to fluctuations in commodity (particularly crude) prices, higher operating netbacks as a result of operating cost efficiencies, the disposition of high operating cost properties, lower interest and financing charges and the realized hedging gains or losses from commodity contracts. In addition, production from new high rate high decline Evi, Alberta and North Dakota Bakken production impacts production and therefore funds from operations before commodity contracts.

Q2 2011 funds from operations were reduced by lower production due to severe weather and flooding and realized losses on commodity contracts. Q3 2011 funds from operations increased due to the monetization of the Company's commodity contracts that realized \$4.5 million. Q4 2011 funds from operations before commodity contracts decreased due to the mid quarter property acquisition of medium crude and natural gas production.

Q1 2010 was higher than the other 2010 quarters due to a higher operating netback due primarily to higher natural gas prices and lower royalties. The increase in Q4 2010 from Q2 and Q3 2010 relates to higher operating netbacks as a result of operating cost efficiencies, the disposition of high operating cost properties and lower general and administrative expenses and finance charges and other fees.

## **Net Asset Value**

			As at Decemb	er 31			2011/2010
(000s \$ Cdn.)	2011	2010	2009	2008	2007	2006	% Change
Present value of proved plus probable reserves, before tax at 10% 1	296,349	201,441	200,832	166,384	87,600	77,100	47
Undeveloped land and seismic <sup>2</sup>	12,000	8,400	3,000	2,900	2,300	1,800	43
Cash proceeds on exercise of stock options <sup>3</sup>	4,243	7,349	2,790	-	166	343	(42)
Total debt ⁴	(55,752)	(18,788)	(28,739)	(48,479)	(20,700)	(28,500)	197
Net asset value before tax	256,840	198,402	177,883	120,805	69,366	50,743	29
Fully diluted common shares outstanding (000s)	165,888	153,027	127,454	101,250	84,207	74,389	8
Net asset value per common share (S/share)	1.55	1.30	1.40	1.19	0.82	0.68	19

<sup>&</sup>lt;sup>1</sup> Based on report of AJM Petroleum Consultants effective December 31, 2011, 2010, 2009, 2008, 2007 and 2006

The Company's net asset value per share increased 19% in 2011 due primarily to full recognition of down spacing at Stanley and Lindahl in North Dakota, accretive property acquisitions in both the US and higher crude prices and positive reserve revisions.

 $<sup>^{\</sup>rm 2}$  Based on management estimate of fair value at December 31, 2011, 2010, 2009, 2008, 2007 and 2006

<sup>&</sup>lt;sup>3</sup> Based on closing price of Arsenal shares at December 31, 2011, 2010, 2009, 2008, 2007 and 2006 of \$0.72, \$1.08, \$0.70, \$0.21, \$0.41 and \$0.078 respectively

<sup>&</sup>lt;sup>4</sup> Total debt includes bank borrowings, debentures outstanding, if applicable, working capital whether excess or deficiency but excludes the value of risk management contracts

#### **OUTLOOK AND 2012 GUIDANCE**

Arsenal has exploration projects in the Glauconite at Princess, in the Cardium and Wilrich at Columbia, and in the Viking at Provost. Two horizontal multistage frack Glauconite wells at Princess are permitted and ready to drill on an 8500 acre land block. The wells are currently scheduled for Q3. At Columbia in the deep basin, Arsenal has a 15,000 acre land block prospective for the Cardium, Wilrich and Gething. A competitor has recently tested offsetting Cardium with two horizontals. Each has tested at 4 mmcf/d of gas with 50 barrels per mmcf of associated liquids. Over time these wells will establish the long term potential of the Cardium. In addition, another competitor has licensed an offset well that may test the Wilrich and Gething formations. Arsenal has acquired land on two Viking horizontal plays. Plans are to evaluate these in 2013.

#### Outlook

Funds from operations in Q4 2011 increased to \$8.4 million, a 67% increase from \$5.0 million in Q4 2010 and funds from operations for 2011 were \$29.3 million, an increase of 64% from \$17.9 million in 2010. With a very favourable crude oil pricing regime and production from current US drilling expected to increase, the Company is encouraged by the potential for further increases in its cash flow in 2012.

During 2011, the North Dakota Industrial Commission approved an application by EOG Resources increasing the allowable drilling density from 1 well to 3 wells per 640 acre spacing unit for parts of the Stanley Bakken and Three Forks pool. Arsenal and partners are currently developing drilling spacing units on the basis of two or three wells (in the case of EOG) per every 640 acre spacing unit and 4 wells per every 1280 acre spacing unit. Ultimately, in order to efficiently develop both the middle Bakken zone and the Three Forks zone, Arsenal believes seven wells; four targeting the middle Bakken and three targeting the Three Forks, per 1280 acre spacing unit may be drilled.

The Bakken and Three Forks formations in these properties are developed utilizing horizontal drilling with ever improving multi stage fracturing technology. The wells produce light oil and have high initial production rates that decline rapidly (within six months) to approximately one third of the initial rate followed by an extended low-decline profile to recover (depending on the spacing unit and zone) between 500,000 and 750,000 barrels of light oil. Low operating costs on these wells result in high netbacks and very attractive economics.

During Q1 2012, the Company spud one of these high working interest wells (80%) and plans on drilling another well (80%) immediately on rig release of the first well and is participating in the current completion of a previously drilled well at Stanley (the Moen - 20% WI). In addition, the Company is participating in a non-operated Bakken well at Stanley (the Admundson - 20% WI) to be drilled in early 2012. Production in 2012 from the drilling of these wells will depend not only on the timing of drilling but also on the availability of stimulation services.

In Canada, at Princess, Alberta, Arsenal plans to drill two horizontal wells into the Glauconitic formation to test the capability of multi fracturing to increase production. If successful, the project has the potential to prove up material oil development opportunities for Arsenal in future years. In addition, at Princess and Provost, the Company has identified a number of oil pools that may be water flood candidates for water flood that would increase reserves and flatten the decline rate.

With the inclusion of a full quarter of production from the November 15, 2011 property acquisition and from the Gjoa Lynn well (60% WI) that came on production in early December 2011, production in Q1 2012 will show a substantial increase from Q4 2011. Volumes will increase further in Q2 2012 from the frack of the Moen well (20% WI) and from the drilling and completion of the Anthony Robert (80% WI), Wade Morris (80% WI) and Amundson (20% WI) wells. These increases will be offset by non-core property dispositions expected to be approximately 150 Boe per day and from the shut in of cash flow negative gas production of approximately 100 Boe per day. Production at the end of Q2 should be approximately 4,200 Boe per day.

The physical price for Arsenal's blend of light and medium crude is currently \$30.00 per barrel below WTI which is in turn trading at an \$18.00 per barrel discount to Brent prices. So although headline oil prices are very high, realized prices for Arsenal and other producers in the industry are well below budgeted expectations. The effect on Arsenal's cash flow is further exacerbated by losses from hedges referenced against WTI prices. This price discounting commenced in March 2012. Arsenal's Q1 2012 results, therefore, will be relatively unaffected. Most analysts predict that the Western Canadian and North Dakota oil price discounts will shrink in June with the end of the refinery turnaround season and that the WTI/Brent discount will shrink with the reversal of the Seaway Pipeline also starting in June.

Arsenal plans to balance cash flow with capital expenditures through the remainder of 2012. This means that projects such as the Princess Glauconite horizontals as well as Bakken wells scheduled for Q3 and Q4 of 2012 may be delayed pending resolution of the oil price discounting.

#### **PRODUCTION AND REVENUE**

#### **Average Daily Production**

Production for Q4 2011 averaged 2,899 Boe per day, a 33% increase from 2,185 Boe per day in Q3 2011 and a 36% increase from 2,132 Boe per day in Q4 2010. For 2011, production averaged 2,230 Boe per day versus 2,093 Boe per day in 2010.

Average Daily Production	Three M	onths Ended I	December 31	Year Ended December 3			
	2011	2010	% Change	2011	2010	% Change	
Canada							
Heavy oil	124	202	(39)	170	252	(33)	
Light oil and NGL's	1,072	717	50	895	748	20	
Natural gas	3,758	2,747	37	2,068	2,693	(23)	
Total Boe	1,822	1,376	32	1,409	1,449	(3)	
US							
Heavy oil	-	-	-	-	-	-	
Light oil and NGL's	1,010	692	46	759	587	29	
Natural gas	400	384	4	372	339	10	
Total Boe	1,077	756	42	821	644	28	
Corporate							
Heavy oil	124	202	(39)	170	252	(33)	
Light oil and NGL's	2,082	1,408	48	1,654	1,336	24	
Natural gas	4,158	3,131	33	2,439	3,032	(20)	
Total Boe	2,899	2,132	36	2,230	2,093	7	

The Company produces in the provinces of British Columbia, Alberta and Saskatchewan in Canada (63% of total Q4 2011 production) and in the state of North Dakota in the US (37% of total Q4 2011 production). For 2011, 63% of production originated in Canada and 37% from the US versus 69% in Canada and 31% from the US in 2010.

The percentage of production from Canada increased in Q4 2011 due to the property acquisition in mid Q4 2011 that added approximately 1,500 Boe per day effective November 15, 2011. US production, that dropped in the current quarter as a percentage of total production due to the Canadian property acquisition, is expected to increase in future as a percentage of total production as the Company commences production from its high rate, high working interest drilling program on the Bakken and Three Forks oil formations in North Dakota.

During 2011, the Company completed and brought on production three high working interest Bakken wells in North Dakota. Production from drilling in the Bakken and Three Forks formations is characterized by high initial production rates, followed by production declines within a few months, after which, production declines and tends to level out. In addition, the production is characterized by low operating costs.

Production of light oil from the Bakken and Three Forks wells drilled in 2011 increased production in the US to average 821 Boe per day versus 644 Boe per day in 2010. Production in Canada in 2011 remained relatively constant averaging 1,409 Boe per day in 2011 versus 1,449 Boe per day in 2010.

Production of heavy oil has declined 39% during the current quarter and 33% during the current year when compared to their corresponding 2010 periods due to property sales, natural production declines and no additional heavy oil drilling.

Production of light oil and NGLs has increased 48% during the current quarter and 24% during 2011 when compared to their corresponding 2010 periods as the Company has concentrated its drilling efforts and program on North Dakota light oil in the Bakken and Three Forks formations.

Production of natural gas increased 33% during the current quarter when compared to the corresponding Q4 2010 quarter due to the November 2011 property acquisition being weighted to natural gas. For the year ended December 31, 2011, production of natural gas declined 20%. Natural declines, the sale of natural gas properties and the lack of natural gas focused drilling accounted for this decline. The Company has deemphasized natural gas drilling due to low prices and the better economics offered by the Company's portfolio of oil projects. In 2012, the percentage of production from natural gas as a percentage of total corporate production is anticipated to decline unless prices significantly improve from current levels.

#### **Production Profile**

Percentage Split - By Commodity	Three Months Ended December 31 Year Ended Decem						
	2011	2010	% Change	2011	2010	% Change	
Heavy oil	4%	10%	(57)	<b>7</b> %	12%	(38)	
Light oil and NGLs	<b>72</b> %	66%	9	<b>75</b> %	64%	17	
Natural gas	24%	24%	(2)	18%	24%	(25)	

Production Split - By Country	Three Mo	onths Ended D		Year Ended D	ecember 31	
	2011	2010	% Change	2011	2010	% Change
Canada	63%	65%	(3)	63%	69%	(9)
US	37%	35%	5	<b>37</b> %	31%	20

#### **Production by Area**

		Three Month	ns Ended D	ecember 31	Year Ended December			
	20	11	20:	10		2011		2010
AREA	Boe/d	% of Total	Boe/d	% of Total	Boe/d	% of Total	Boe/d	% of Total
Canada					'			
Galahad (light oil and solution gas)	185	6	299	14	237	8	239	11
Wildmere (heavy oil)	-	-	-	-	-	-	50	2
Chauvin/Ribstone (medium oil and gas)	301	10	324	15	312	11	313	15
West Current (BC gas)	-	-	25	1	-	-	39	2
Evi (light oil)	206	7	189	9	244	8	209	10
Princess	216	7	27	1	98	3	41	2
Desan (BC gas)	339	12	-	-	85	3	41	2
Provost/Consort	348	12	78	4	101	3	83	4
Others	227	8	434	21	332	26	434	21
Total Canada	1,822	63	1,376	65	1,409	63	1,449	69
US								
Stanley (light oil)	822	28	436	20	550	23	367	18
Lindahl (light oil)	160	6	225	11	173	9	179	9
Rennie Lake (light oil)	42	1	42	2	43	1	44	2
Others	53	2	53	2	55	4	54	3
Total US	1,077	37	756	35	821	37	644	31
Total	2,899	100	2,132	100	2,230	100	2,093	100

In Q4 2011 the Company closed a property acquisition adding natural gas production at Desan and both natural gas and medium crude production at Princess and Provost/Consort. In Q3 2010, the Company sold its heavy oil interests at Wildmere and natural gas interests at West Current. The decrease in the Galahad production in Q4 2011 from Q4 2010 relates to production of a solution gas cap that produced proficiently in Q3 2010 but that has subsided over the past few quarters. Part of the decline of the production of high rate solution gas has been replaced by higher crude production from the area. Evi production increased in 2011 due to late 2010 and early 2011 drilling. The Company typically drills at Evi in Q1 and Q4 adding high initial rate production. Evi wells typically decline substantially during their first few months of production. Production has been added in 2011 from drilling at Stanley where high initial rate production declines quickly and stabilizes in 6 – 9 months. Production at Stanley and Lindahl will increase substantially over time with the drilling of additional Bakken and Three Forks wells in these areas. Arsenal's other properties experienced expected production declines.

#### Revenue

#### **Prices**

Prices - Before Commodity Contracts	Three M	onths Ended I	December 31		December 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						
Heavy oil per barrel	81.85	60.34	36	70.84	61.92	14
Light oil and NGL's per barrel	90.61	73.39	23	83.54	68.30	22
Natural gas per mcf	2.76	3.15	(12)	3.24	3.87	(16)
Total per Boe	64.56	53.35	21	66.33	53.22	25
US						
Heavy oil per barrel	-	-	-	-	-	-
Light oil and NGL's per barrel	87.15	68.50	27	85.55	69.95	22
Natural gas per mcf	4.52	3.78	19	4.72	4.24	11
Total per Boe	83.43	64.62	29	81.24	66.05	23
Total						
Heavy oil per barrel	81.85	60.34	36	70.84	61.92	14
Light oil and NGL's per barrel	88.93	70.99	25	84.47	69.03	22
Natural gas per mcf	2.93	3.23	(9)	3.47	3.91	(11)
Total per Boe	71.57	57.34	25	71.82	57.17	26

Reference Prices	Three M	onths Ended D	December 31	Year Ended Decer		
	2011	2010	% Change	2011	2010	% Change
WTI Cushing, Oklahoma (\$U.S./bbl)	98.75	76.06	30	95.00	77.54	23
Light Oil Edmonton Par 40 API (\$Cdn./bl	97.87	74.77	31	95.16	76.84	24
Hardisty Bow River 24.9 API (\$Cdn./bbl	87.16	64.21	36	78.30	68.02	15
AECO (daily spot) (\$Cdn./MMBtu)	3.29	3.55	(7)	3.65	4.13	(12)
Henry Hub NYMEX Close (\$U.S./MMBu)	3.55	4.38	(19)	4.04	4.59	(12)
Foreign exchange (\$Cdn./\$U.S.)	0.98	0.96	2	1.01	0.97	4

The Company sells crude oil under 30-day evergreen contracts. Natural gas production is sold in the spot market. The commodity prices received by the Company are reflective of the movement in commodity prices over the comparative periods.

The price the Company received for heavy oil and light oil and NGL's increased 36% and 23% respectively in Canada in the current quarter versus Q4 2010 and 14% and 22% for the current year over 2010. The increase in the Hardisty Bow River stream (24.9 API), that represents a reference price of the average price the Company receives for its heavy oil, increased 36% in the current quarter over Q4 2010 and 15% in the current year over 2010. The current quarter increase in the price of light oil over the previous quarter and for the current year over 2010 is consistent with the increase in the exchange adjusted price of WTI over those periods. The price received for natural gas generally tracks changes to the AECO price down 7% for the current quarter and 12% for the current year versus previous comparative periods.

In the US, the increase in WTI (30% over the previous comparative quarter and 23% over 2010) was somewhat negated by the strengthening of the Canadian dollar (up 2% over prior comparative quarter and 4% over the prior year) and the movement of the North Dakota differentials.

The Company received an average price per Boe during Q4 2011 of \$71.57 per Boe an increase of 25% from \$57.34 per Boe received in Q4 2010. For 2011, the average price received was \$71.82 per Boe up 26% from \$57.17 per Boe received in 2010. This increase is primarily attributed to a higher price for light oil and NGL's and is consistent with the upward movement in crude prices over these periods.

#### Oil and Gas Revenue

	Three M	onths Ended D	ecember 31		Year Ended December 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						
Heavy oil	931,095	1,122,360	(17)	4,390,188	5,686,361	(23)
Light oil and NGL's	8,939,074	4,838,251	85	27,280,739	18,657,119	46
Natural gas	954,226	796,293	20	2,445,192	3,799,733	(36)
Total	10,824,395	6,756,904	60	34,116,119	28,143,213	21
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	8,098,666	4,359,757	86	23,709,080	14,998,031	58
Natural gas	166,348	133,482	25	640,738	524,476	22
Total	8,265,014	4,493,239	84	24,349,818	15,522,507	57
Total						
Heavy oil	931,095	1,122,360	(17)	4,390,188	5,686,361	(23)
Light oil and NGL's	17,037,740	9,198,008	85	50,989,819	33,655,150	52
Natural gas	1,120,574	929,775	21	3,085,930	4,324,209	(29)
Oil and natural gas revenues	19,089,409	11,250,143	70	58,465,937	43,665,720	34
Gain (loss) on realized commodity contracts	(346,955)	267,123	-	3,356,993	1,788,624	88
Oil and gas revenue after commodity contracts	18,742,454	11,517,266	63	61,822,930	45,454,344	36
Per boe before commodity contracts	71.57	57.34	25	71.82	57.17	26
Per boe after commodity contracts	70.27	58.71	20	75.95	59.51	28

Oil and gas revenues for Q4 2011 increased 70% from Q4 2010 due to a 36% increase in average production for the quarter and to a 25% increase in the average price received per Boe. A higher light oil commodity profile that receives a higher price per barrel than either medium and heavy oil or natural gas on a Boe basis was a large factor in the price increase. These factors offset a 2% appreciation of the Canadian dollar and a 9% decline in the average natural gas price received by the Company.

For 2011, oil and gas revenues increased 34% due to a 7% increase in average production for the year and due to a 26% increase in the average price received per Boe. This price increase incorporates a 4% increase in the strength of the Canadian dollar that results in lower US prices and revenues in Canadian dollar terms from that recognized in 2010.

Despite the strengthening of the Canadian dollar of 2% in Q4 2011 over Q4 2010, increased production of 42% resulted in oil and natural gas revenues generated from production in the US in Q4 2011 increasing to \$8.3 million up 84% from \$4.5 million for Q4 2010. For 2011, despite the 4% increase in the strength of the Canadian dollar, US production revenues increased 57% in 2011 to total \$24.3 million up from \$15.5 million for 2010. Higher crude prices and higher production from drilling offset the revenue translation loss from the stronger Canadian dollar.

Oil and gas revenues from Canadian production totaled \$10.8 million for the current quarter versus \$6.8 million in the comparative 2010 quarter. While production increased 32% in the current quarter due to the mid-quarter property acquisition, the product mix was more heavily weighted to lower priced natural gas. For the current year, oil and gas revenues in Canada increased to \$34.1 million versus \$28.1 million in 2010. Higher commodity prices and slightly higher production offset 2010 and 2011 property sales and natural declines and an emphasis on US drilling.

#### **Commodity Price Risk Management**

Financial instrument contracts are recorded in the consolidated financial statements at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss in the consolidated statements of loss. In Q1 2011, the Company recorded a loss of \$3.2 million on its commodity contracts. In Q2 2011, because of a drop in future commodity prices from March 31, 2011, the Company recorded a gain of \$2.3 million. In Q3 2011 the Company monetized all of its commodity contracts which resulted in a Q3 quarter gain of \$6.0 million. In Q4 2011, to lock in the metrics of a portion of the Company's property transaction, the Company entered into three commodity contracts covering parts of 2011, 2012 and 2013. These contracts resulted in a loss in Q4 2011 of \$3.4 million, a combination of a realized loss of \$346,955 (\$1.30 per Boe) and an unrealized loss of \$3.8 million. The 2011 net gain is a combination of a realized gain of \$3.4 million (\$4.12 per Boe) and an unrealized loss of \$2.4 million.

At December 31, 2011, the Company has a liability recorded in its financial statements totaling \$3.8 million. This loss relates to contracts whose settlement dates are in the future and is based on a December 31, 2011 WTI Canadian dollar strip price and the term of the Company's contracts of approximately \$99.25 Canadian per barrel. The future price and therefore the future liability will change with changes to the WTI forward strip prices and to the Canadian/US exchange rate.

The Company has a policy of entering into commodity contracts to stabilize funds from operations against volatile commodity prices in order to ensure a certain level of capital reinvestment and to protect the metrics of significant acquisitions (as it did in November 2011). Currently, the Company has four commodity contracts with terms as follows.

(\$Cdn.)			
Commodity Sold Volume Sold		Remaining Term	Pricing
Oil	300 bbl per day	Jan 1, 2012 - Dec 31, 2012	100.00 per bbl
Oil	300 bbl per day	Jan 1, 2012 - Dec 31, 2013	92.10 per bbl
Oil	400 bbl per day	Jan 1, 2012 - Dec 31, 2013	92.10 per bbl
Oil	300 bbl per day	Jan 1, 2013 - Dec 31, 2013	101.00 per bbl

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into a swap contract fixing the base interest rate on \$40 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's credit facility, subject to additional stamping fees from 2.00% to 3.50% depending on the debt to cash flow ratio, as defined, and as calculated at the Company's most recent quarter end.

(\$Cdn.)					
Subject of Contract	Term	Notional Quantity	Reference	Strike Price	Option Traded
30 day BA rate	Feb 13, 2012 - Feb 13, 2015	\$20,000,000	CAD - BA - CDOR	1.50%	Swap

## **Royalties**

	Three	Months Ended D	ecember 31		Year Ended I	December 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						
Heavy oil	181,219	187,957	(4)	769,767	806,071	(5)
Light oil and NGL's	1,526,038	695,781	119	4,264,993	3,004,478	42
Natural gas	78,312	(36,780)	(313)	118,622	195,800	(39)
Total	1,785,569	846,958	111	5,153,382	4,006,349	29
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	2,341,280	1,069,135	119	6,509,050	3,722,069	75
Natural gas	28,812	35,853	(20)	115,053	98,392	17
Total	2,370,092	1,104,988	114	6,624,103	3,820,461	73
Total						
Heavy oil	181,219	187,957	(4)	769,767	806,071	(5)
Light oil and NGL's	3,867,318	1,764,916	119	10,774,043	6,726,547	60
Natural gas	107,124	(927)	-	233,675	294,192	(21)
Royalties	4,155,661	1,951,946	113	11,777,485	7,826,810	50

Percentage By Product	Three Mo	Year Ended December 31				
	2011	2010	% Change	2011	2010	% Change
Heavy oil	19	17	16	18	14	24
Light oil and NGL's	23	19	18	21	20	6
Natural gas	10	-	-	8	-	-
Total	22	17	25	20	18	12

Percentage By Country	Three Months Ended December 31				Year Ended December 31		
	2011	2010	% Change	2011	2010	% Change	
Canada	16	13	32	15	14	6	
US	29	25	17	27	25	11	
Total	22	17	25	20	18	12	

The Company's royalty rate for Q4 2011 averaged 22%, up from 17% in Q4 2010. The higher Q4 2011 rate relates to higher royalties on Alberta production at Evi and Princess in Q4 2011 due to the expiry of the low royalty rate period of one year and to higher rate US production in the current quarter. For 2011 the royalty rate averaged 20% of gross revenues versus 18% in 2010.

Going forward, the corporate royalty rate is expected to average in the 20% - 22% range. The rate fluctuates due to the timing of low royalty production in Canada, production increases from higher royalty rate US wells and to some degree commodity prices and production rates. Increases or decreases in the dollar value of royalties are commodity price related with higher commodity prices resulting in a higher dollar value and lower commodity prices resulting in a lower dollar value.

Per Boe	Three M	onths Ended D	ecember 31		December 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						
Heavy oil per barrel	15.93	10.10	58	12.42	8.78	42
Light oil and NGL's per barrel	15.47	10.55	47	13.06	11.00	19
Natural gas per mcf	0.23	(0.15)	256	0.16	0.20	21
Total per Boe	10.65	6.69	59	10.02	7.58	32
US						
Heavy oil per barrel	-	-	-	-	-	-
Light oil and NGL's per barrel	25.20	16.80	50	23.49	17.36	35
Natural gas per mcf	0.78	1.02	(23)	0.85	0.80	7
Total per Boe	23.93	15.89	51	22.10	16.26	36
Total						
Heavy oil per barrel	15.93	10.10	58	12.42	8.78	42
Light oil and NGL's per barrel	20.19	13.62	48	17.85	13.80	29
Natural gas per mcf	0.28	(0.00)	-	0.26	0.27	(1)
Royalties per Boe	15.58	9.95	57	14.47	10.25	41

On a Boe basis, royalty rates were \$15.58 per Boe for Q4 2011 and \$114.47 per Boe for 2011, both up from comparative period but in line with the changes to commodity prices over the respective periods and the new royalty rates on new production from drilling. The Q4 2010 rate per Boe was lower that Q4 2011 due to low royalty rate production from Evi and Princess in Alberta. An increase in the Boe rate is expected as a result of a higher percentage of revenue from the US that attracts higher royalty rates than in Canada. As royalty holiday periods expire and as higher royalty production is brought on-stream as is the case on our new US production, the rate per Boe is expected to increase and rates are expected to average the higher side of the expected range of 20% to 22% of revenue. In 2012, the Company plans on drilling horizontal wells at Princess that would be eligible for a low royalty rate of 5% for a period of time.

## **Operating Expenses**

Field Operating Expenses	Three Mo	onths Ended D	ecember 31		Year Ended D	December 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change	
Canada							
Heavy oil	371,001	406,230	(9)	1,414,114	2,179,649	(35)	
Light oil and NGL's	2,896,484	1,682,352	72	7,611,949	5,859,729	30	
Natural gas	760,601	573,173	33	2,041,252	1,922,326	6	
Total	4,028,086	2,661,755	51	11,067,315	9,961,704	11	
US							
Heavy oil	-	-	-	-	-	-	
Light oil and NGL's	889,680	746,382	19	3,469,131	3,385,927	2	
Natural gas	-	-	-	-	-	-	
Total	889,680	746,382	19	3,469,131	3,385,927	2	
Total							
Heavy oil	371,001	406,230	(9)	1,414,114	2,179,649	(35)	
Light oil and NGL's	3,786,164	2,428,734	56	11,081,080	9,245,656	20	
Natural gas	760,601	573,173	33	2,041,252	3,040,028	(33)	
Operating expenses	4,917,766	3,408,137	44	14,536,446	14,465,333		

Field Operating Per Boe	Three Mon	ths Ended D	ecember 31	Year Ended December		
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						
Heavy oil per barrel	32.62	21.84	49	22.82	23.74	(4)
Light oil and NGL's per barrel	29.36	25.52	15	23.31	21.45	9
Natural gas per mcf	2.20	2.27	(3)	2.70	1.96	38
Total per Boe	24.03	21.02	14	21.52	18.84	14
US						
Heavy oil per barrel	-	-	-	-	-	-
Light oil and NGL's per barrel	9.57	11.73	(18)	12.52	15.79	(21)
Natural gas per mcf	-	-	-	-	-	-
Total per Boe	8.98	10.73	(16)	11.57	14.41	(20)
Total						
Heavy oil per barrel	32.62	21.84	49	22.82	23.74	(4)
Light oil and NGL's per barrel	19.76	18.74	5	18.36	18.96	(3)
Natural gas per mcf	1.99	1.99	-	2.29	2.75	-
Operating expenses per Boe	18.44	17.37	6	17.86	18.94	(6)

Field operating costs in Q4 2011 averaged \$18.44 per Boe versus \$17.37 per Boe in Q4 2010. The 6% increase from Q4 2010 relates to the addition of purchased properties in Q4 2011 and the field work undertaken to improved production and add reserves, to an increased number of workovers in the US (otherwise, US operating costs would have been lower in the quarter) and to increased industry costs generally. Production added in the Q4 2011 property acquisition has higher average operating costs per Boe than that previously recorded and experienced by the Company.

For the year ended December 31, 2011, field operating costs were \$17.86 per Boe down from 2010 of \$18.94 per Boe. The decrease over the comparative years relate to 2010 field initiatives to lower field operating costs, the sale of high operating cost properties and the addition of high rate production from low operating cost Bakken properties in North Dakota.

It is expected that the low cost Bakken/Three Forks production added in future years in North Dakota, will offset the higher operating cost acquired properties and field operating costs should remain within the range of \$19.00 to \$21.00 per Boe.

#### **Transportation Expenses**

Transportation expenses reflect the cost of delivering production to the custody transfer point of the purchaser and are incurred in British Columbia, Alberta, Saskatchewan and in the US and include gathering, processing and transmission costs, gas service costs (firm and interruptible) and costs to truck clean oil. Generally no transportation costs are recorded on the Company's US properties as the sale of commodities in the US occurs at the lease and therefore costs to transport, truck or gather products sold are for the account of the purchaser. On some of the Company's US wells, the Company must transport the clean crude to the delivery (sales) point by truck or rail car and can therefore incur these transportation expenses.

Transportation Expenses	Three Mo	nths Ended D	ecember 31	Ye	ecember 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						
Heavy oil	15,266	16,608	(8)	70,571	82,092	(14)
Light oil and NGL's	137,836	138,123	(0)	1,103,392	623,969	77
Natural gas	-	1,182	-	-	111,359	-
Total	153,102	155,913	(2)	1,173,963	817,420	44
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	43,534	73,701	41	112,777	3,438	3,180
Natural gas	3,561	(4,689)	-	3,561	(1,804)	297
Total	47,095	69,012	32	116,338	1,634	7,020
Total						
Heavy oil	15,266	16,608	(8)	70,571	82,092	(14)
Light oil and NGL's	181,370	211,824	(14)	1,216,169	627,407	94
Natural gas	3,561	(3,507)	-	3,561	109,555	(97)
Transportation expenses	200,197	224,925	(11)	1,290,301	819,054	58

Transportation Expenses Per Boe	Three Months Ended December 31		ecember 31	Yea	Year Ended December 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada						_
Heavy oil per barrel	1.34	0.89	50	1.14	0.89	27
Light oil and NGL's per barrel	1.40	2.10	(33)	3.38	2.28	48
Natural gas per mcf	-	-	-	-	0.11	-
Total per Boe	0.91	1.23	(26)	2.28	1.55	48
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	0.47	1.16	60	0.41	0.02	2,438
Natural gas	0.10	(0.13)	173	0.03	(0.01)	280
per Boe	0.48	0.99	(52)	0.39	0.01	5,483
Total						
Heavy oil	1.34	0.89	50	1.14	0.89	27
Light oil and NGL's	0.95	1.63	(42)	2.01	1.29	57
Natural gas	0.01	(0.01)	176	-	0.10	
Transportation expenses per Boe	0.75	1.15	(35)	1.59	1.07	48

Transportation costs during the current quarter decreased by 11% on a dollar basis and 35% on a Boe basis to \$200,197 and \$0.75 per Boe. For 2011, costs increased 58% on a dollar basis and 48% on a Boe basis to \$1,290,301 and \$1.59 per Boe. Lower costs in Q4 2011 related to better weather and therefore improved field conditions in Canada versus poor wet snowy weather a year ago that increased trucking costs.

In Q4 2011, transportation costs were lower due to additional volumes from the property acquisition in November and improved field condition making trucking easier and cheaper. Higher costs in 2011 were incurred in both Canada and the US due to additional trucking required due to wet weather and road load restrictions and in Canada due to a pipeline break at Evi, Alberta requiring the Company to truck oil to market. The repairs to the damaged pipeline were completed and shipping on the pipeline resumed in September 2011. Natural gas transportation costs in 2010 represent costs in BC on a property sold in Q3 2010.

## **Operating Netback**

	Three Months Ended December 31			Three Mor			
		2011		2010			Corporate
(\$Cdn.)	Canada	US	Corporate	Canada	US	Corporate	% Change
Heavy oil							
Revenue	81.85	-	81.85	60.34	-	60.34	36
Royalty	(15.93)	-	(15.93)	(10.10)	-	(10.10)	58
Operating	(32.62)	-	(32.62)	(21.84)	-	(21.84)	49
Transportation	(1.34)	-	(1.34)	(0.89)	-	(0.89)	50
Operating netback per barrel	31.97	-	31.97	27.50	-	27.50	16
Light oil and NGL's							
Revenue	90.61	87.15	88.93	73.39	68.50	70.99	25
Royalty	(15.47)	(25.20)	(20.19)	(10.55)	(16.80)	(13.62)	48
Operating	(29.36)	(9.57)	(19.76)	(25.52)	(11.73)	(18.74)	5
Transportation	(1.40)	(0.47)	(0.95)	(2.10)	(1.16)	(1.63)	(42)
Operating netback per barrel	44.38	51.91	48.04	35.22	38.81	36.99	30
Natural gas							
Revenue	2.76	4.52	2.93	3.15	3.78	3.23	(9)
Royalty	(0.23)	(0.78)	(0.28)	0.15	(1.02)	-	-
Operating	(2.20)	-	(1.99)	(2.27)	-	(1.99)	-
Transportation	=	(0.10)	(0.01)	-	0.13	0.01	(176)
Operating netback per mcf	0.33	3.64	0.65	1.03	2.90	1.25	(48)
Boe							
Revenue	64.56	83.43	71.57	53.35	64.62	57.34	25
Royalty	(10.65)	(23.93)	(15.58)	(6.69)	(15.89)	(9.95)	57
Operating	(24.03)	(8.98)	(18.44)	(21.02)	(10.73)	(17.37)	6
Transportation	(0.91)	(0.48)	(0.75)	(1.23)	(0.99)	(1.15)	(35)
Operating netback per Boe	28.97	50.05	36.80	24.42	37.00	28.88	27

	Y	Year Ended December 31			Year Ended December 31		
		2011			2010		Corporate
	Canada	US	Corporate	Canada	US	Corporate	% Change
Heavy oil							
Revenue	70.84	-	70.84	61.92	-	61.92	14
Royalty	(12.42)	-	(12.42)	(8.78)	-	(8.78)	42
Operating	(22.82)	-	(22.82)	(23.74)	-	(23.74)	(4)
Transportation	(1.14)	-	(1.14)	(0.89)	-	(0.89)	27
Operating netback per barrel	34.46	-	34.46	28.51	-	28.51	21
Light oil and NGL's							
Revenue	83.54	85.55	84.47	68.30	69.95	69.03	22
Royalty	(13.06)	(23.49)	(17.85)	(11.00)	(17.36)	(13.80)	29
Operating	(23.31)	(12.52)	(18.36)	(21.45)	(15.79)	(18.96)	(3)
Transportation	(3.38)	(0.41)	(2.01)	(2.28)	(0.02)	(1.29)	57
Operating netback per barrel	43.79	49.14	46.25	33.57	36.78	34.98	32
Natural gas							
Revenue	3.24	4.72	3.47	3.87	4.24	3.91	(11)
Royalty	(0.16)	(0.85)	(0.26)	(0.20)	(0.80)	(0.27)	(1)
Operating	(2.70)	-	(2.29)	(1.96)	-	(2.75)	(17)
Transportation		0.03	-	(0.11)	0.01	(0.10)	-
Operating netback per mcf	0.38	3.85	0.91	1.60	3.46	0.80	14
Boe							
Revenue	66.33	81.24	71.82	53.22	66.05	57.17	26
Royalty	(10.02)	(22.10)	(14.47)	(7.58)	(16.26)	(10.25)	41
Operating	(21.52)	(11.57)	(17.86)	(18.84)	(14.41)	(18.94)	(6)
Transportation	(2.28)	(0.39)	(1.59)	(1.55)	(0.01)	(1.07)	48
Operating netback per Boe	32.51	47.18	37.91	25.26	35.38	26.91	41

The netback from heavy oil increased 16% for Q4 2011 and by 21% for 2011 to \$31.97 per barrel and to \$34.46 per barrel due primarily to higher prices and lower operating costs. The netback from light oil also increased in Q4 2011 and in 2011 by 30% to \$48.04 per barrel and by 32% to \$46.25 per barrel. Higher prices offset higher royalties and higher transportation expenses. Transportation expenses for light oil increased trucking expenses of light crude in 2011 due to an oil pipeline break at Evi, Alberta. Natural gas netbacks declined 48% in the current quarter to \$0.65 per mcf due to lower prices but increased in 2011 by 14% to \$0.91 per mcf due to a Q3 2011 adjustment to a prior period accrual in the US to prices and operating expenses.

Arsenal's corporate operating netback increased 27% in the current quarter to \$36.80 per Boe and by 41% to \$37.91 per Boe for the current year due to increased prices. Higher prices offset higher royalties and for 2011 higher transportation expenses.

Realized commodity contract losses for Q4 2011 reduced the operating netback by \$1.30 per Boe to \$35.50 per Boe. Realized commodity contract gains for 2011 increased operating netback by \$4.12 per Boe to \$42.03 per Boe. Realized commodity contracts added \$1.36 per Boe and \$2.34 per Boe to the operating netback for Q4 2010 and 2010 respectively.

#### **General and Administrative Expenses**

	Three Mo	Three Months Ended December 31			Year Ended December 31		
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change	
Gross expenditures	1,322,144	1,160,773	14	5,578,968	4,809,226	16	
Overhead recovery	(413,255)	(236,556)	75	(963,121)	(710,609)	36	
Capitalized overhead	(161,000)	(161,000)	0	(644,000)	(532,000)	21	
Net general and administrative expense	747,889	763,217	(2)	3,971,847	3,566,617	11	
Net general and administrative per boe	2.80	3.89	(28)	4.88	4.67	4	

For Q4 2011, gross general and administrative expenditures were slightly higher than Q4 2010 by \$161,371. On a net basis, the general and administrative expenditures decreased by \$15,328. For 2011, gross general and administrative expenditures increased by \$769,742 when compared to the 2010. Net expenditures for increased by \$405,230 when compared to 2010.

General and administrative increased as higher salaries and benefits increased due to the higher number of employees, a severance paid to an employee, higher audit and consulting fees related to the conversion to IFRS, higher reserve evaluation fees due to the Q4 2011 property acquisition, higher filing fees due a higher number of shares outstanding and higher consulting fees related to increased activity.

Overhead recovery increased due to the increase in the dollar value of operated capital projects and the number of operated wells increased over the prior comparative quarter.

The Company capitalizes overhead directly related to exploration and development activities. For 2011, the Company's capitalized overhead, excluding share based compensation, increased as a result of an additional employee whose salary and related benefits are capitalized.

On a Boe basis, general and administrative costs for the current quarter declined to \$2.80 per Boe. For 2011, net general and administrative expenses were up 4% or \$0.21 per Boe to \$4.88 per Boe due to higher costs offset somewhat by higher average production. General and administrative expenses should decrease on a Boe basis in 2012 as onetime costs are eliminated, as office occupancy costs decrease and as average production from both Canada (as a result of the late year property acquisition) and from the US (from drilling) increases.

## **Exploration and Evaluation Expenses**

	Three Mo	nths Ended D	ecember 31		Year Ended D	ecember 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Exploration and evaluation	830,570	641,847	29	5,663,250	2,250,984	152

Under IFRS, Arsenal expenses all pre-license costs, all seismic expenditures and all dry hole costs. In 2011, the Company expensed costs recorded at December 31, 2010 as "Exploration and Evaluation" assets as their status had yet to be determined. These costs related primarily to drilling costs on wells that were drilling over year end or on wells that had been drilled and required further evaluation. Subsequent to year end, it was determined that some of the wells were unproductive and therefore abandoned. Accordingly the related costs were expensed. In addition, during Q1 2011 additional expenses were incurred in the drilling of three (2.0 net) dry holes. In Q1 2011, the Company incurred seismic expenditures primarily on the Edgerton prospect that have been expensed. In Q2 2011, the Company incurred some minor additional exploration expenses and reversed an accrual made in the previous quarter. In Q3 2011, the Company drilled a dry hole at Chauvin and in Q4 2011; the Company expensed \$793,443 to purchase and reprocess seismic in Alberta at Princess and Provost.

#### **Property, Plant and Equipment Impairment**

	Three	Months Ended	December 31		Year Ended I	December 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Property, plant and equipment impairment	1,000,000	5,948,300	(83)	5,500,000	5,948,300	-
Per boe	3.75	30.32	(88)	6.76	7.79	(13)

The carrying amounts of the Company's property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the assets' recoverable amount or fair value is estimated based on certain industry value metrics. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. The discount rates used by management to estimated future cash flows ranged from 10% for a high forward price, low risk light oil CGU to 20% for a low forward price, dry natural gas CGU. Production and timing of proved and probable reserves was determined by the Company's third party independent engineers. Management does not expect a significant difference between value in use and fair value less costs to sell.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its value in use or estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

On March 31, 2011, the impairment test indicated that the costs recorded in one CGU exceeded the estimated recoverable amount and accordingly, an impairment provision of \$2.5 million was recognized. On September 30, 2011, the impairment test indicated that the costs recorded in one other CGU exceeded the estimated recoverable amount and accordingly, an impairment provision of \$2.0 million was recognized. On December 31, 2011, the Company assessed impairment and an impairment provision was required in the Company's heavy oil CGU that had negative reserve revisions at December 31, 2011. The impairment test resulted in an impairment charge of \$1.0 million. As the recoverable amount of the CGU's are sensitive to commodity prices, further impairment charges could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse and impairment charges recorded to date, less applicable depletion and depreciation charges.

#### **Acquisition Expense**

	Three M	onths Ended	December 31		Year Ended I	December 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Other expense	613,611	-	-	613,611	-	-

In November 2011, the Company acquired producing properties in British Columbia (Desan) and in Alberta (Princess and Provost) for \$38.6 million. In addition to the acquisition price, the Company incurred certain acquisition expenses related to the acquisition. Under previous Canadian GAAP, these costs were capitalized as part of the full cost capital pool. Under IFRS, these costs are required to be expensed. These costs include legal fees, financial consulting fees related to the transaction, reserve evaluation fees related to the properties to be acquired and other miscellaneous expenses.

#### **Interest and Other Financing Expenses**

Interest and other financing expenses include interest, bank charges and fees and other charges paid on the Company's credit facility, interest paid on the Company's unspent flow-through share obligation and other government and vendor charges.

	Three Mo	nths Ended [	December 31		Year Ended D	December 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Interest and other financing expenses	380,726	161,977	135	933,990	1,019,755	(8)
Per boe	1.43	0.83	73	1.15	1.34	(14)

Interest and other financing fees increased 135% in the Q4 2011 quarter due to the mid quarter property acquisition of \$38.6 million funded entirely with debt and due to the fees related to the evaluation and increase in the Company's credit facility from \$60.0 million to \$75.0 million as a result of the acquisition.

For 2011, interest and other financing charges decreased 8% from 2010 due to lower average borrowings during the comparative periods offset by slightly higher interest rates. The equity financing completed in February 2011 eliminated debt for most of the 2011 year as did the proceeds from commodity contracts monetized in Q3 2011. Capital spending over the year, in excess of cash flow, increased borrowing. The average borrowing balance for Q4 2011 was \$28.9 million versus \$6.0 million for Q3 2011 and \$8.5 million for Q4 2010. For 2011, the average borrowing for year was \$11.1 million versus \$16.1 million for 2010.

In November 2011 as a result of a review by the banking syndicate of the acquisition and of the Company's internally prepared engineering report, the Company's credit facility increased from \$60.0 million to \$75.0 million at rates ranging from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on bankers' acceptances and on Libor based loans.

With the change of the credit facility and the increase in the Company's credit facility from \$40.0 million at the beginning of the year to \$60.0 million in May 2011 and \$75.0 million in November 2011, the Company incurred higher bank and legal fees related to the credit facility than the fees paid in 2010. In addition, the higher prime rate of interest this year offset any further decrease in the Company's borrowing costs in 2011.

### **Depletion and Depreciation Expense**

	Three Months Ended December 31				Year Ended December 31	
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
	4,557,946	3,025,386	51	12,893,856	12,843,385	-
Per boe	17.09	15.42	11	15.84	16.81	(6)
Canada	16.52	20.03	(18)	18.85	20.94	(10)
US	18.06	7.02	157	10.68	7.53	42

As a result of the conversion to IFRS, the Company now depletes and depreciates its property, plant and equipment based on its total proved plus probable reserves as opposed to proved reserves that were used under previous GAAP.

Despite a 36% increase in production quarter over comparative quarter, depletion and depreciation for Q4 2011 increased 51% on a dollar basis and 11% on a Boe basis over Q4 2010. On a Boe basis, depletion and depreciation increased to \$17.09 per Boe in Q4 2011 from \$15.42 per Boe in Q4 2010. The increases of 51% on a dollar basis and 11% on a Boe basis from Q4 2010 is primarily attributable to the addition of higher cost reserves in the November 2011 property acquisition and to the increase in future capital needed to develop reserves in the US. Future capital increased in the US due to higher cost environment and due to addition of some additional drilling locations.

For 2011, the depletion and depreciation rate decreased 6% to \$15.84 per Boe. This was due primarily to property impairment provisions made throughout 2010 and in 2011 offset slightly by higher cost reserve additions from the November 2011 property acquisition and higher future development costs.

#### Accretion

(\$Cdn.)	Three	e Months Ended	December 31		Year Ended	December 31
	2011	2010	% Change	2011	2010	% Change
Accretion	216,560	175,800	23	708,499	756,042	(6)
Per boe	0.81	0.90	(9)	0.87	0.99	(12)

Accretion is the increase or decrease in the reporting period in the present value of the Company's decommissioning liabilities that are discounted using a risk free interest factor of 2.8%. Accretion decreased 9% on a Boe basis in Q4 2011 to \$0.81 per Boe and decreased 12% for 2011 to \$0.87 per Boe from 2010 comparatives.

#### **Share-based Compensation**

	Three Mo	nths Ended D	ecember 31		Year Ended D	ecember 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Share-based compensation expense	396,896	344,763	15	1,405,166	1,050,827	34

The Company uses the fair value method for valuing share based compensation. Under this method, the compensation cost attributed to stock options granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase in contributed surplus.

For the year ended December 31, 2011, the Company granted 4,840,000 (December 31, 2010 – 4,280,000) options at a weighted average price of \$0.68 (December 31, 2010 - \$0.88) per share to employees, officers and directors. These options vest annually over three years and expire five years from date of grant. In addition, during the year ended December 31, 2011, 1,342,833 (December 31, 2010 – 171,500) options were exercised at a weighted average price of \$0.42 (December 31, 2010 \$0.46) per share and 1,557,997 (December 31, 2010 – 676,000) options at a weighted average price of \$0.81 (December 31, 2010 - \$1.18) per share were forfeited or expired unexercised.

For 2011, share-based compensation increased 34% over that recorded in 2010. Increases and decreases during the various reporting periods result from the number of options issued, the timing of issue and the valuation and vesting of options issued in 2009, 2010 and during 2011.

During 2011 the Company capitalized to property plant and equipment \$294,480 (2009 - \$166,172) of stock based compensation representing stock based compensation relating to exploration overhead capitalized.

#### **Income Tax Expense**

	Three Mo	Three Months Ended December 31			Year Ended D	ecember 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Deferred tax expense	542,928	(217,023)	(350)	3,084,214	1,070,899	188

For the year ended December 31, 2011, the Company recorded a net deferred income tax expense of \$3,084,214. The net deferred income tax expense consists of a deferred income tax expense relating to the US operations of \$3,877,181 and a deferred income tax reduction of \$792,967 relating to Canadian operations. Low margins, depletion and depreciation expense, interest and other financing charges and general and administrative expenses were primarily responsible for the loss before income taxes and the resultant reduction of deferred income taxes in Canada for the year. In US, high operating margins, and reasonably low interest and other financing charges and general and administrative expenses contributed to income before taxes of \$10.1 million.

At December 31, 2011, the future income tax asset is related to the Canadian operations of \$1,775,276 and the future income tax liability of \$5,496,305 is related to the US operations.

Arsenal does not expect to pay current tax in Canada or in the US until at least 2014 based on current tax pools, current commodity price forecasts and expected capital expenditures. Arsenal has a total of \$105.5 million of pools available in Canada claimable at rates of between 10% - 100% and \$19.8 million of pools available in the US \$12.5 million of which is claimable at 100%.

#### **Funds from Operations and Net Loss**

Funds from Operations	Three Months Ended December 31 Year Ended December 3		ecember 31			
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Cash provided by operating activities	2,872,022	5,358,828	(46)	25,301,234	11,082,654	128
Seismic expenses	793,443	53,900	1,372	1,555,130	1,663,037	(6)
Decommissioning obligations settled	311,396	90,174	245	819,283	1,083,838	(24)
Change in non-cash working capital	4,463,654	(460,965)	(1,068)	1,598,245	4,042,961	(60)
Funds from operations	8.440.515	5.041.937	67	29.273.892	17.872.490	64

Funds From Operations By Country	Three Months Ended December 31				Year Ended	December 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change
Canada	3,955,202	2,980,599	33	16,251,620	11,366,791	43
US	4,485,313	2,061,338	118	13,022,272	6,505,699	100
Funds from operations	8,440,515	5,041,937	67	29,273,892	17,872,490	64

Funds From Operations Netback per Boe	Three Months Ended December 31			nds From Operations Netback per Boe Three Months Ended December 31 Year End			ar Ended De	ecember 31
(\$Cdn.)	2011	2010	% Change	2011	2010	% Change		
Canada	23.59	23.53	0	31.60	21.50	47		
US	45.28	29.65	53	43.45	27.68	57		
Total	31.65	25.70	23	35.96	23.40	54		

Funds From Operations and Net (Loss)	Three Month	s Ended Dece	mber 31	Year Ended Decembe		
(\$Cdn.)	2011	2010	Change	2011	2010	Change
Funds from operations	8,440,515	5,041,937	67	29,273,892	17,872,490	64
Per share						
Basic	0.05	0.04	25	0.18	0.13	38
Diluted	0.05	0.04	25	0.18	0.13	39
Net loss	(4,051,189)	(6,443,517)	37	(2,545,214)	(6,291,319)	(60)
Per share						
Basic	(0.03)	(0.05)	40	(0.02)	(0.05)	66
Diluted	(0.03)	(0.05)	40	(0.02)	(0.05)	66

Funds from operations for Q4 2011 totaled \$8.4 million (\$0.05 per share basic and diluted) or \$31.65 per Boe versus \$5.0 million (\$0.04 per share basic and diluted) or \$25.70 per Boe for Q4 2010. The increase relates to higher production and higher operating netbacks the result of operating cost efficiencies and the disposition of high operating cost properties.

For 2011, funds from operations totaled \$29.3 million (\$0.18 per share basic and diluted) or \$35.96 per Boe versus \$17.9 million (\$0.13 per share basic and diluted) or \$23.40 per Boe in the 2010 comparative year. The operating netback in 2011 was \$37.91 per Boe versus \$26.91 per Boe in 2010 and realized commodity contract proceeds added \$4.12 per Boe to the cash netback in 2011 versus \$2.34 per Boe in 2010.

The decrease in the Company's net loss for Q4 2011 to \$4.1 million (\$0.03 per share basic and diluted) from a net loss of \$6.4 million (\$0.05 per share basic and diluted) in Q4 2010 was primarily the result of higher production,

prices and operating margins in Q4 2011 that offset higher exploration and evaluation expenses and the future income tax provision.

For the year ended December 31, 2011, the Company recorded a net loss of \$2.5 million (\$0.02 per share basic and diluted) versus a net loss of \$6.3 million (\$0.05 per share basic and diluted) in 2010. The 2011 improvement in net loss results from higher production and prices that resulted in higher operating margins. Higher 2011 exploration and evaluation expenses reduced the benefit of operating margin gains.

#### **Comprehensive Loss**

The Company's comprehensive loss includes unrealized foreign exchange gains and losses resulting from the translation into Canadian dollars of the Company's US subsidiary. Net loss was decreased for a translation gain on foreign operations by \$47,133 for 2011 (loss of \$199,996 in 2010). Comprehensive loss therefore for 2011 totaled \$2.5 million versus \$6.5 million for 2010.

#### **Select Annual Information**

	IFRS	IFRS		
(\$Cdn.)	2011	2010	2009	
Oil and gas revenue	58,465,937	43,665,720	36,941,862	
Funds from operations	29,273,892	17,872,490	169,485	
Net loss	(2,545,214)	(6,291,319)	(11,050,516)	
Income (loss) per share, basic and diluted	(0.02)	(0.05)	(0.11)	
Total assets	170,985,816	92,595,917	116,880,416	
Total debt	55,751,531	18,787,775	28,739,421	

#### **Summary of Quarterly Results**

		IFRS						
			2011			20	10	
(\$Cdn.)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas revenue	19,089,409	15,027,512	12,729,872	11,619,144	11,250,143	9,701,018	11,128,046	11,586,513
Net income (loss)	(4,051,189)	6,433,903	3,011,927	(7,939,855)	(6,443,517)	(353,425)	574,691	(69,068)
Per share - basic	(0.03)	0.04	0.02	(0.05)	(0.05)	(0.00)	0.00	(0.00)
Per share - diluted	(0.03)	0.04	0.02	(0.05)	(0.05)	(0.00)	0.00	(0.00)
Funds from operations	8,440,515	11,425,975	4,301,767	5,105,635	5,041,937	3,633,712	4,007,438	5,189,403
Per share - basic	0.05	0.05	0.03	0.03	0.04	0.03	0.03	0.04
Per share - diluted	0.05	0.05	0.03	0.03	0.04	0.03	0.03	0.04
Total assets	170,985,816	107,432,402	97,040,147	101,005,848	92,595,917	87,035,956	92,271,525	92,871,950
Total debt (1)	55,751,531	9,240,010	9,931,680	6,871,378	18,787,775	15,061,052	19,886,286	20,318,893
Shares outstanding	157,282,261	135,123,761	161,761,062	163,314,306	140,812,472	133,734,472	134,195,472	134,773,390

Includes Bank debt, working capital and convertible debentures outstanding but excludes risk management contracts and future income taxes whether current or long term assets or liabilities.

Arsenal's quarterly results have fluctuated significantly in the past eight quarters due to a variety of factors that include commodity price and production swings, the timing of drilling and completions particularly in the US and in Alberta at Evi and the rationalization of properties and operating costs. Arsenal has been and expects to continue to rationalize its asset base focusing on properties with a long reserve life and high netbacks where the Company has a strategic, technical or financial advantage. Quarterly results therefore will continue to fluctuate somewhat and will depend on property dispositions, the movement in commodity prices particularly for oil, the differentials in medium, heavy oil and North Dakota oil and the timing of drilling programs in North Dakota and Canada. With the establishment and maintenance of a core low decline property base coupled with the continuing implementation of operational efficiencies, a more stable commodity market and continued drilling success in North Dakota, the Company expects its established production base to increase steadily which should lead to more comparative and stable results going forward.

#### **Contractual Obligations**

In the ordinary course of business, the Company enters into various contractual obligations, including the following:

- purchase of services
- royalty agreements
- operating agreements
- transporting, processing and treating agreements
- right-of-way and road use agreements
- lease obligations for office space and equipment
- flow-through share agreements

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. Obligations at December 31, 2011 with a fixed term are as follows:

(\$Cdn.)	2012	2013	2014	2015	2016
Firm service transportation commitments	269,479	269,479	258,304	226,375	176,813
Lease of office premises	365,795	-	-	-	-
Office equipment lease	48,516	40,430	-	-	-
Field equipment leases	96,882	41,883	9,626	-	-
Total	780,672	351,792	267,930	226,375	176,813

The Company has met all of its flow-through share commitments as required under the various flow-through share agreements.

The Company entered into a sublease with a subtenant for a term that commenced February 1, 2010 and ends on February 29, 2012. The sublease has reduced the Company's total commitment under its head lease by \$60,776 for 2012. The Company's office lease expires July 31, 2012. The Company has exercised its option to extend its current lease for an additional five years at market rates to be determined on May 1, 2012. The Company expects the renewal to be in the range of \$22.00 - \$25.00 per square foot. In addition, the Company will be required to pay building operating costs, property taxes and parking, estimated to total approximately \$16.50 per square foot.

The Company has no off balance sheet arrangements other than operating leases for office space and equipment as disclosed above.

For the Year Ended December 31, 2011 (\$ Cdn.)	Canada	U.S	Total
Oil and gas revenue	34,116,119	24,349,818	58,465,937
Operating income	16,721,459	14,140,246	30,861,705
Income (loss) after income taxes	(8,770,944)	6,225,730	(2,545,214)
Exploration and evaluation assets (as at December 31, 2011)	9,100,169	-	9,100,169
Property, plant and equipment (as at December 31, 2011)	108,386,178	37,808,164	146,194,342
Property, plant and equipment expenditures	7,392,266	23,714,888	31,107,154
Exploration and evaluation expenditures	9,363,845	-	9,363,845
Property acquisitions	38,574,702	-	38,574,702
Property dispositions	(621,914)	-	(621,914)

For the Year Ended December 31, 2010 (\$ Cdn.)	Canada	U.S	Total
Oil and gas revenue	28,143,213	15,522,507	43,665,720
Operating income	12,229,513	8,325,010	20,554,523
Income (loss) after income taxes	(9,264,656)	2,973,337	(6,291,319)
Exploration and evaluation assets (as at December 31, 2010)	6,394,505	-	6,394,505
Property, plant and equipment (as at December 31, 2010)	56,003,187	18,327,839	74,331,026
Property, plant and equipment expenditures	7,311,489	7,616,163	14,927,652
Exploration and evaluation expenditures	11,028,488	-	11,028,488
Property acquisitions	75,480	2,184,049	2,259,529
Property dispositions	(5,919,077)	-	(5,919,077)

Canada

(31,141)

(334,489)

38,157,408

(9,563,911)

(792,967)

(8,770,944)

**United States** 

8,993,928

10,102,911

3,877,181

6,225,730

## **Segmented Statement of Operations by Country**

Year Ended December 31, 2011

Gain on sale of property

Income (loss) before income taxes

Deferred tax expense (reduction)

Foreign exchange gain

Income taxes

Net income (loss)

Revenue			
Petroleum and natural gas	34,116,119	24,349,818	58,465,937
Royalties	(5,153,382)	(6,624,103)	(11,777,485)
	28,962,737	17,725,715	46,688,452
Realized gain (loss) on risk management contracts	2,437,826	919,167	3,356,993
Unrealized gain (loss) on risk management contracts	(2,807,066)	451,957	(2,355,109)
	28,593,497	19,096,839	47,690,336
Expenses			
Operating and transportation	12,241,278	3,585,469	15,826,747
Transportation			-
General and administrative	2,514,799	1,457,048	3,971,847
Exploration and evaluation	5,663,250	-	5,663,250
Property, plant and equipment impairment	5,500,000	-	5,500,000
Depletion and depreciation	9,692,254	3,201,602	12,893,856
Accretion	538,783	169,716	708,499
Interest and other financing	353,897	580,093	933,990
Property acquisition	613,611	-	613,611
Share-based compensation	1,405,166	-	1,405,166

(31,141)

(334,489)

539,000

3,084,214

(2,545,214)

47,151,336

Total

Company

Year Ended December 31, 2010			Total
	Canada	<b>United States</b>	Company
Revenue			
Petroleum and natural gas	28,143,213	15,522,507	43,665,720
Royalties	(4,005,113)	(3,821,697)	(7,826,810)
	24,138,100	11,700,810	35,838,910
Realized gain (loss) on risk management contracts	1,957,458	(168,834)	1,788,624
Unrealized gain (loss) on risk management contracts	(1,441,981)	18,090	(1,423,891)
	24,653,577	11,550,066	36,203,643
Expenses			
Operating	11,091,167	3,374,166	14,465,333
Transportation	817,420	1,634	819,054
General and administrative	2,226,210	1,340,407	3,566,617
Exploration and evaluation	2,197,553	53,431	2,250,984
Property, plant and equipment impairment	5,948,300	-	5,948,300
Depletion and depreciation	11,074,005	1,769,380	12,843,385
Accretion	580,321	175,721	756,042
Interest and other financing	709,685	310,070	1,019,755
Share-based compensation	1,050,827	-	1,050,827
Gain on sale of property	(1,282,406)	-	(1,282,406)
Foreign exchange gain realized	(52,339)		(52,339)
Foreign exchange gain unrealized	38,511	-	38,511
	34,399,254	7,024,809	41,424,063
Income (loss) before income taxes	(9,745,677)	4,525,257	(5,220,420)
Income taxes			
Deferred tax expense (reduction)	(481,021)	1,551,920	1,070,899
Net income (loss)	(9,264,656)	2,973,337	(6,291,319)

As the Company focuses its capital program on drilling Bakken and Three Forks oil prospects in North Dakota, it is expected that the US operations will generate a more significant portion of the Company's production, revenues, reserves and profits.

## **Bank Loan, Liquidity and Capital Resources**

## **Capital Management**

In order to continue the Company's ongoing exploration and development program, the Company must maintain a strong capital base. A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company is committed to establishing and maintaining a strong capital base to ensure the Company has access to the equity and debt markets when deemed advisable. In order to maintain a strong capital base, the Company continually monitors the risk reward profile of its exploration and development projects and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. It then determines increases or decreases to its capital budget and what, if any, additional initiatives may need to be implemented.

The Company considers shareholder's equity, bank loan and working capital (excess or deficiency) as components of its capital base. The Company can access or increase its capital base through the issuance of shares and through

bank borrowings that are based on reserves. The Company can safeguard its capital base by stabilizing its funds from operations, by fixing, or reviewing the advisability of fixing, interest rates and commodity prices on all or a portion of the Company's debt and production, by closely monitoring expenses and by closely monitoring and scrutinizing the results of its capital expenditure program and adjusting capital expenditures as required based on economic conditions and drilling results.

The Company monitors its capital base based primarily on its debt to annualized funds flow ratio and its debt to equity ratio. Debt includes bank borrowings, plus or minus working capital and excludes decommissioning obligations and risk management contracts (whether an asset or an obligation). Annualized funds flow is calculated as cash flow from operations, before changes in non-cash working capital, decommissioning obligations settled and seismic expenses, from the Company's most recent guarter multiplied by four adjusted, if required, by increasing or decreasing commodity price expectations, future production profiles, the Company's risk management position and other non-recurring operational items. The Company's goal is to target this ratio at 1.50 : 1 but the ratio can and will fluctuate based on the timing of property transactions, commodity prices and on the mix of exploratory and development drilling. During periods of extreme commodity price declines, high drilling activity or after large property or corporate acquisitions, it is expected that the ratio would increase and during periods of high commodity prices and low activity levels, it is expected that the ratio would decrease. The Company's focus in these instances is to concentrate on bringing the ratio back into the target range. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. The Company prepares an annual operating and capital expenditure budget. The budget is updated, at least quarterly, and when critical factors change and when actual results are realized and compared to budget. Critical factors include economic factors such as the state of equity markets, changes to commodity prices, interest rates and foreign exchange rates and non economic factors such as drilling results and production profiles. The Company's board of directors approves the budget and reviews changes thereto. The Company has targeted a debt to equity ratio of 0.5 : 1. This ratio will also fluctuate over time depending on the state of equity markets and the results of operations.

At December 31, 2011, the Company's net debt to annualized funds flow (Q4 cash flow adjusted for significant and non-recurring realized commodity gains or losses and seismic expenditures expensed) ratio was 1.65: 1 and its debt to equity ratio was 1.02: 1. Conversion to IFRS reduced equity by approximately \$28.1 million primarily as a result of the fair value assessment by CGU and the adjustment to decommissioning obligations. An equity issue generating net proceeds of approximately \$19.8 million in February 2011 increased equity and reduced debt improving the debt to annualized funds flow ratio and the debt to equity ratio. The property acquisition of \$38.6 million in November 2011 increased debt thereby increasing the debt to annualized funds flow ratio. Property impairment of \$5.5 million reduced equity thereby increasing the debt to equity ratio. At December 31, 2011, the net debt to annualized funds flow ratio and the debt to equity ratio, while higher than the targeted ratios are within an acceptable target range as established in management's strategic goals and guidelines given recent events and transactions. Key factors that will determine if the Company will be able to return to within its established guidelines are the state of equity markets, production rates from drilling, commodity (particularly crude) prices, interest and foreign exchange rates and the magnitude and timing of capital requirements to drill and complete wells in the Bakken and Three Forks plays in North Dakota.

(\$Cdn.)	December 31, 2011
Bank loan	52,062,272
Working capital deficiency	
(excluding risk management contracts)	3,689,259
Total debt	55,751,531
Annualized funds from operations	33,762,060
Total debt to annualized funds flow ratio	1.65
Shareholders' Equity	54,872,949
Debt to equity	1.02

The Company expects to focus the greater part of its 2012 capital budget in the US in North Dakota on Bakken drilling at Stanley and in Alberta at Provost and Princess, on drilling horizontal walls and initiating water flood on certain oil pools.

The Company's share capital is not subject to external restrictions.

There were no changes in the Company's approach to capital management during 2011. In 2012 however due to the nature of the Company's 2012 expenditure profile of low risk Bakken drilling in the US and low risk water flood programs in Canada, the Company adjusted its debt to forward cash flow ratio from 1:00: 1 to 1:50: 1.

#### **Credit Facility**

In May 2011, the Company's credit facility was reviewed, syndicated and increased from \$40.0 million to \$60.0 million based on the independent engineering report as at December 31, 2010. A review and update of the credit facility in November 2011, incorporated reserve information from the \$38.6 million property acquisition and incorporated drilling results since June 2011, and resulted in an increase in the credit facility to \$75.0 million. The credit facility is available in Canadian and/or US dollar prime loans or in Bankers Acceptances and/or Libor borrowings. Interest on the Company's credit facility is at rates ranging from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on Bankers Acceptances and on Libor based loans. The interest rate is set based on the Company's debt, as calculated for this purpose to include bank loan plus working capital (excess or deficiency), outstanding letters of credit and other miscellaneous items, if any, but excludes decommissioning obligations and risk management contracts (whether an asset or an obligation) to trailing funds flow ratio (funds flow for the last two quarters annualized) adjusted for interest and other financing expenses, expensed seismic expenditures, realized hedging gains or losses and any unusual or non-recurring items.

The credit facility has a revolving period of 364 days plus one year and is extendible annually. If not extended, the credit facility will automatically convert to a one year non-revolving term loan and all obligations under the credit facility are to be repaid or paid at the end of the one year period.

The credit facility is secured by an unlimited liability guarantee to the lenders, a ISDA Master Agreement, a demand debenture in the amount of \$300 million granting a first priority security interest over all present and after acquired personal property and a first floating charge over all present and after acquired petroleum and natural gas interests and mortgages creating specific fixed charges on some of the oil and gas properties of the Company in North Dakota.

The credit facility is also subject to certain positive and negative covenants including a covenant not to dispose of assets or property having a fair aggregate value exceeding 5% of the borrowing base without an assessment of an adjustment to the borrowing base. In addition, the credit facility is subject to a semiannual borrowing base review based on internally generated engineering.

The Company's credit facility has a financial covenant that, without the written consent of the lender, would result in a breach of the agreement. The Company cannot permit:

The adjusted working capital ratio (as defined in the agreement to include the unutilized portion of the facility and to exclude the value of any risk management contracts) to fall to below 1:1.

At December 31, 2011, the Company was in compliance with this covenant.

At December 31, 2011, debt under the credit facility amounted to \$52,062,272 and includes \$5,000,000 of US dollar denominated borrowings (\$5,181,200 Cdn.).

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into a swap contract fixing the base interest rate on \$20 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's credit facility, subject to additional stamping fees from 2.00% to 3.50% depending on the debt to cash flow ratio, as defined, and as calculated at the Company's most recent quarter end.

(\$Cdn.)					
Subject of Contract	Term	Notional Quantity	Reference	Strike Price	Option Traded
					_
30 day BA rate	Feb 13, 2012 - Feb 13, 2015	\$20,000,000	CAD - BA - CDOR	1.50%	Swap

### Liquidity

Crude prices have improved over the past year and have recently stabilized in the \$90.00 - \$110.00 US range. Natural gas prices have fallen over the past few years and are now in the \$2.00 - \$2.50 Canadian \$2.25 - 2.50 US range. Access to equity markets for oil weighted companies is available, albeit at a significant discount to net asset value. Increased crude prices have led to an improvement in the Company's funds from operations and its access to capital. In February 2011, the Company completed an equity issue for net proceeds of \$19.8 million. The Company is well positioned and has available the financial resources necessary to undertake a 2012 capital expenditure program that is expected to cost more than its 2012 projected funds from operations. Even with a capital program, higher than funds flow from operations, the Company can remain within an industry acceptable level of debt and within its current range of its debt to annualized funds flow from operations ratio of 1.65 : 1. In the event that commodity prices, interest or exchange rates, or other factors negatively impact funds flow from operations, the Company, while it has the ability to access equity markets, anticipates that it will reduce the capital program to safeguard its capital base with the goal of having debt staying not only within the Company's credit facility but also within its targeted debt to forward annualized funds flow from operations ratio.

In order to further ensure that funds are available to assist in the financing of the Company's capital program and to ensure positive returns from the Company's capital development and acquisition program, the Company utilizes commodity hedges to lock in commodity prices. During Q3 2011, with the sudden drop in the price of crude, the Company monetized all of its crude contracts realizing proceeds of \$4.5 million. The Company therefore at September 30, 2011 had no commodity contracts in place. In Q4 2011, on closing of the \$38.6 million property purchase, the Company entered into two crude oil commodity contracts and in early 2012, with the continued increase in crude prices, the Company entered into two additional crude oil commodity contracts. Terms of these contracts are as follows:

As a result of these crude commodity contracts, the Company has commodity contracts selling 1,000 barrels of oil per day for 2012 at an average price of \$94.47 per barrel and 1,000 barrels per day for 2013 at an average price of \$94.77 per barrel.

Commodity contracts may be monetized or additional commodity contracts may be put in place, depending on the Company's financial position, changes in commodity prices and the expected level of the Company's capital expenditure program, production and cash flow.

#### **Share Capital**

In February 2011, the Company, pursuant to a short form prospectus, issued 22,158,500 common shares at \$0.95 per share for gross proceeds of \$21.1 million (net proceeds of \$19.8 million).

On June 16, 2011, the Company announced its intention to make a normal course issuer bid ("NCIB") that commenced June 20, 2011 and ends June 19, 2012. A total of 8,128,724 common shares may be acquired under the bid representing 5% of the common shares outstanding as of June 14, 2011. To December 31, 2011, the Company has purchased 5,458,544 common shares at an average cost of \$0.65 per share plus expenses. To date in 2012, the Company has purchased an additional 1,051,500 common shares at an average cost of \$0.67 per share plus expenses.

In May 2010, the Company announced it had received approval for a normal course issuer bid ("NCIB") commencing May 31, 2010 and ending May 30, 2011. As at December 31, 2010, the Company had acquired 1,403,918 common shares under the bid at an average price of \$0.82 per share plus acquisition costs. To May 30, 2011, the Company acquired an additional 1,573,000 common shares under the bid at an average price of \$0.79 per share plus acquisition costs.

During 2011, 4,840,000 stock options at a weighted average price of \$0.68 per share were issued, 1,342,833 options at a weighted average exercise price of \$0.42 were exercised for proceeds of \$560,807 and 1,557,997 options at a weighted average price of \$0.81 per share were forfeited or expired unexercised.

At December 31, 2011, the Company has 157,282,261 common shares and 14,693,670 options at a weighted

## **Common Shares**

		Year Ended		Year Ended		
	Decei	mber 31, 2011	December 31, 2010			
	Shares	\$	Shares	\$		
Balance - beginning of year	140,812,472	122,609,238	120,461,890	106,471,683		
Issued under prospectus offering	22,158,500	21,050,575	21,583,000	18,315,650		
Share issue costs	-	(1,694,307)	-	(1,161,279)		
Issued on exercise of options	1,342,833	560,807	171,500	79,150		
Transferred from contributed surplus	-	469,834	-	65,318		
Purchases under normal course innuer bid	(7,031,544)	(6,136,161)	(1,403,918)	(1,161,284)		
Balance - end of year	157,282,261	136,859,986	140,812,472	122,609,238		

## **Options**

	Year Ended
	December 31, 2011
Balance - beginning of period	12,754,500
Exercise of options	(1,342,833)
Options issued	4,840,000
Options forfeited or expired	(1,557,997)
Balance - end of period	14,693,670

As of the date of this MD&A, the Company has 156,284,094 common shares and 14,387,003 options outstanding.

## **Common Shares**

December 31 to
March 21, 2012
157,282,261
53,333
(1,051,500)
156,284,094

## **Options**

	December 31 to
	March 21, 2012
Balance - beginning of period	14,693,670
Exercise of options	(53,333)
Options issued	150,000
Options forfeited or expired	(403,334)
Balance - end of period	14,387,003

# **Related Party Transactions**

An officer of the Company is a partner in a law firm that provides legal services to the Company. During the year ended December 31, 2011, the Company recorded a total of \$175,706 (December 30, 2010 - \$262,265) for legal fees and disbursements. As at December 31, 2011, accounts payable and accrued liabilities include \$25,000 (December 31, 2010 - \$35,000) related to these fees and disbursements.

All related party transactions have been recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

# **Capital Expenditures**

	Three Months	Three Months	Three Months	Three Months	Year
	Ended March 31	Ended June 30 En	ded September 30 En	ided December 31	Ended December 31
(\$ Cdn.)	2011	2011	2011	2011	2011
Land	475,300	9,593	98,080	1,628,012	2,210,985
Drilling and completions	5,541,670	3,560,597	7,279,407	6,030,842	22,412,516
Capitalized general and administrative	250,999	231,169	201,666	257,646	941,480
Production equipment, facilities and tie-ins	1,106,297	683,762	1,101,998	2,932,196	5,824,253
Other	282,432	3,784	2,015,520	(2,901,330)	(599,594)
Total property plant and equipment additions	7,656,698	4,488,905	10,696,671	7,947,366	30,789,640
Non-cash additions	(372,421)	(70,179)	(2,056,186)	2,816,300	317,514
<b>Total Property, Plant and Equipment Expenditures</b>	7,284,277	4,418,726	8,640,485	10,763,666	31,107,154

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Year Ended December 31
\$ Cdn.)	2011	2011	2011		2011
Land	1,522,821	1,747,215	-	1,906,611	5,176,647
Drilling and completions	3,343,643	(61,191)	(3,452)	908,198	4,187,198
Total Exploration and Evaluation Expenditures	4.866.464	1.686.024	(3,452)	2.814.809	9.363.845

	Three Months	Three Months	Three Months	Three Months	Year
	Ended March 31	Ended June 30	Ended September 30	Ended December 31	Ended December 31
(\$ Cdn.)	2011	2011	2011		2011
Total Seismic	732,048	3,793	25,844	793,445	1,555,130

	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31	Year Ended December 31
(\$ Cdn.)	2011	2011	2011	2011	2011
Total Property Acquisitions				38,574,702	38,574,702

	Three Months	Three Months	Three Months	Three Months	Year
	Ended March 31	Ended June 30	Ended September 30	Ended December 31	Ended December 31
(\$ Cdn.)	2011	2011	2011	2011	2011
Total Property Dispositions	(472,591)	(125,918)	(23,405)	-	(621,914)

Capital expenditures for 2011 to property, plant and equipment totaled \$31.1 million up from \$14.9 million in 2010. Expenditures on exploration and evaluation totaled \$9.4 million in 2011 compared to \$11.0 million in 2010. In addition, the Company expensed \$1.6 million of seismic expenditures in 2011 compared to \$1.7 million in 2010. In 2011 capital spending totaled \$40.5 million up 56% over \$26.0 million expended during 2010.

In 2011, the Company participated in the drilling of 12 gross (9.02 net) wells. Four (3.0 net) of the wells were dry and abandoned and ultimately written off to exploration and evaluation expense.

At Stanley, North Dakota, the Company participated in the completion and equipping of two (1.40 net) Company operated wells drilled in 2010, drilled, completed and equipped two gross (0.62 net) wells, one partner operated (0.03 net) and one Company operated (0.59 net).

At Evi, Alberta four wells were drilled, three resulted in dry holes and one (1.00 net well) was completed and is productive. In 2011 at Edgerton, the Company drilled and completed one net well at Edgerton, that is being evaluated as a heavy oil producer, and at Provost drilled five gross (4.4 net) drilling one net dry hole and 3.4 net oil wells.

During 2011, the Company incurred seismic expenditures that were expensed, of \$1,555,130 on projects at Edgerton, Provost and Princess, all in Alberta. During 2011, the Company closed the sale of three noncore low netback properties netting \$621,914.

#### **Decommissioning Obligations**

The Company's decommissioning obligations represent the Company's accounting estimate of its share of the present value of future costs to be incurred to abandon and reclaim the Company's pipelines, wells and facilities. Increases in the obligation year over year result from the obligations arising from drilling activities, acquisitions, increases in estimated costs or changes to timing to abandon and reclaim wells and from the quarterly increase in the present value of the obligation (accretion). Decreases in the obligation year over year result from property dispositions, decreases in estimated costs or changes to timing to abandon and reclaim wells and costs incurred in settlement of abandonment obligations. At December 31, 2011, the Company has estimated and recorded a decommissioning obligation of \$37.3 million (December 31, 2010 - \$19.7 million) based on a total liability of \$52.4 million (December 31, 2010 - \$32.1 million. The increase results primarily from the decommissioning obligations assumed in the Q4 property acquisition.

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and gas properties:

	Year Ended	Year Ended
(\$Cdn.)	December 31, 2011	December 31, 2010
Balance, beginning of year	19,667,331	21,182,129
Obligations settled	(819,283)	(1,083,838)
Obligations acquired	18,703,225	20,216
Obligations disposed of	(435,710)	(2,726,393)
Obligations incurred	621,681	683,760
Change in estimated future cash outflows	(1,214,237)	1,109,054
Foreign currency translation	94,440	(273,639)
Accretion expense	708,499	756,042
Balance, end of year	37,325,946	19,667,331

# **Commitments and Contingencies**

## **Outstanding lawsuits**

Various lawsuits have been filed against the Company for incidents which arose in the ordinary course of business. In the opinion of management and legal counsel, the outcome of the lawsuits, now pending, is not material to the Company's operations. Should any loss result from the resolution of these claims, such loss will be charged to operations in the period of resolution.

## **Risk Factors**

Arsenal is subject to multiple business risks that are similar to other entities involved in the conventional energy sector. Arsenal's financial position, results of operations and funds from operations are directly impacted by the following factors:

## Commodity price risk

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Company uses financial derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize funds from operations available for future development programs. The Company does not enter into derivative contracts for speculative purposes. At December 31, 2010, the Company had in place six crude oil commodity contracts covering 2011 and 2012. In 2011, the Company added two additional crude oil commodity contracts. During Q3 2011, based on weak crude oil commodity prices, the Company monetized all of its then outstanding contrast realizing a gain of \$4.5 million in the quarter. In Q4 2011, to protect the metrics of a property acquisition, the Company entered into two commodity contracts and in Q1 2012 entered into two additional contracts. (see Liquidity section of this MD&A).

#### **Production risk**

Production risk relates to the Company's ability to produce, process and transport crude oil and natural gas. To manage this risk to an acceptable level, the Company performs regular and proactive maintenance on its wells, facilities and pipelines. The Company operates approximately 85% of its production, which affords greater control over operations. Approximately 37% of the Company's Q4 2011 production is in the United States.

#### **Natural Decline and Reserve Replacement Risk**

Natural decline risk relates to the Company's ability to replace reserves in excess of annual production declines through development activities such as water floods, drilling, well completions, well workovers and other capital activities. The Company manages its business using a portfolio approach whereby capital is allocated across a number of areas so that significant capital is not risked on any one activity. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

The Company's reserves are evaluated on an annual basis by independent third-party consultants reporting to the Company's Reserves Committee of the Board of Directors. The Company's approach is to invest in mature, long-life properties with a high proved producing component combined with low-risk development opportunities where the reserve risk is generally lower and cash flows are more stable and predictable. The Company will engage in exploration activities only after considerable due diligence has been completed on the play, including geological, geophysical and total capital required.

#### **Environmental Health and Safety Risk**

Environment, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place as well as operational loss insurance coverage. Arsenal employees and contractors adhere to the Company's environment, health and safety program, which is routinely reviewed and updated to ensure that the Company operates in a manner consistent with best practices in the industry. The Board of Directors oversees the risk assessment and risk mitigation process.

### **Regulation, Tax and Royalty Risk**

Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Company's financial and operating results. Management, with the assistance of legal and accounting professionals, stay informed of proposed changes in laws and regulations and proactively responds to and plan for the effects of these changes.

#### **Capital Market Risk**

The Company's ability to maintain its financial strength and liquidity is dependent upon its ability to access Canadian capital markets. If Canadian debt or equity markets were to become less accessible to the Company, it may affect the ability of Arsenal to continue to replace production.

For a more detailed discussion of the Risk Factors, refer to the Company's Annual Information Form filed on SEDAR at www.sedar.com.

# **Critical Accounting Estimates and Policies**

The significant accounting policies used by the Company are outlined in note 3 to the consolidated financial statements for the years ended December 31, 2011 and 2010. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported statement of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates.

### **Critical Accounting Estimates**

Management is often required to make judgments, assumptions and estimates in the application if IFRS that may have a significant impact on the financial results of the Company. The preparation of financial information in accordance with IFRS requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. The following is a summary of key areas where critical accounting estimates are made:

Financial statement item	Critical accounting estimates
Depletion and depreciation expense	Quantities of proved and probable reserves; future development costs related to proved and probable reserves; residual values
Impairment of property, plant and equipment	Future commodity prices; volumes of production and reserves; operating, capital and other costs; discount rates
Exploration and evaluation assets	Likelihood of future benefits before proved or probable reserves have been established

Decommissioning liabilities and related accretion expense

Share-based compensation expense

Fair value of derivative instruments
Deferred income taxes

Timing and amount of cash flows required to settle the liabilities; risk free interest rate

Expected life of stock options; expected forfeiture rate; expected share price volatility; risk-free interest rate

Amount and timing of future cash flows; discount rates Interpretations of current tax legislation; future taxable income; timing of reversal of temporary difference and related tax rates in effect

# **Change in Accounting Policies**

# International Financial Reporting Standards ("IFRS")

On January 1, 2011, IFRS became the generally accepted accounting principles in Canada for profit-oriented publicly accountable enterprises. Arsenal adopted IFRS for financial reporting purposes using a transition date of January 1, 2010. The adoption of IFRS required restatement of comparative amounts reported by the Company for the year ended December 31, 2010. As a result, the Company's financial results for the year ended December 31, 2010 and interim periods in 2010 are reported under IFRS while selected historical data continues to be reported under former Canadian GAAP.

The adoption of IFRS did not have a material impact on net cash flows. It did have a material impact on certain accounting policies and Arsenal's reported financial position and results of operations. The most significant areas of impact for Arsenal include property plant and equipment, asset retirement obligations, accounting for share-based payments and deferred taxes (formerly "future taxes").

### IFRS 1: First Time Adoption of IFRS 1

The adoption of IFRS requires the application of IFRS 1 – First-time Adoption of International Financial Reporting Standards ("IFRS1") which provides guidance for the initial adoption of IFRS. IFRS 1 generally requires that an entity retrospectively apply IFRS policies in its entirety effective at the end of its first IFRS reporting period except where specific IFRS 1 optional and mandatory exemptions permit an alternative treatment. Arsenal applied the following optional exemptions to its opening IFRS statement of financial position of January 1, 2010.

#### Property, Plant and Equipment

The Company elected to apply the IFRS 1 exemption to deem the opening net book value of its property, plant and equipment recorded under the full cost oil and natural gas accounting pool under Canadian GAAP at the date of transition (January 1, 2010) as the deemed cost for its property, plant and equipment under IFRS. The Company had not recognized any exploration and evaluation assets under Canadian GAAP and accordingly did not recognize any exploration and evaluation assets under IFRS. The net book value was allocated to producing and development assets based on proven plus probable reserves. The Company was required to conduct an impairment test, under IFRS standards at the transition date.

## **Decommissioning Obligations**

In accordance with IFRS 1, if the exemption for full cost oil and natural gas accounting is taken, then the decommissioning obligations must be remeasured at the date of transition with any difference charged to deficit.

#### **Share-based Payments**

As provided in IFRS 1, Arsenal elected not to apply IFRS 2 - Share-Based Payments for share-based payments which vested before January 1, 2010.

IFRS allows certain other optional exemptions; however, such exemptions were assessed to be either not applicable or not significant to Arsenal's adoption of IFRS.

The following discussion uses the IFRS standards and interpretations currently issued and in effect at the end of Arsenal's first IFRS reporting period of December 31, 2011.

### **Impacts of IFRS on Accounting Policies**

The adoption of IFRS results in accounting policies that are significantly different from those under former Canadian GAAP:

### **Exploration and Evaluation Expenditures:**

Under Canadian GAAP, Arsenal capitalized these costs and depleted such costs within the full cost pool. Under IFRS, costs including the costs of acquiring leases and licenses, directly attributable general and administrative costs and drilling costs on wells not yet fully evaluated, are capitalized as exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centers, by field or in exploration areas pending determination of technical feasibility and commercial viability. Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

Under IFRS, pre-license costs, seismic costs and all dry holes are expensed as incurred.

## **Property, Plant and Equipment:**

#### **Development Costs**

Under previous Canadian GAAP, the Company applied full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves were capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of production method based on total proved reserves determined using estimated future prices and costs. Capitalized costs were subject to a two part ceiling test using undiscounted proven reserves and discounted (based on a risk free discount rate) of proven and probable reserves. On transition to IFRS, Arsenal was required to adopt new accounting policies for pre-exploration costs, exploration and evaluation costs and development costs.

Under IFRS, development costs are expenditures incurred at an area or property level where technical and commercial feasibility have been determined. These costs are capitalized and accumulated in cash generating units (CGU"S). The Company determined that it had seven CGU and costs were allocated to CGU's based on reserve volumes. Development costs are depleted on a unit-of-production basis over an area or on a CGU level and are subject to an impairment test. Arsenal calculates depletion on an area basis using proved and probable reserves.

#### **Property Sales**

Divestitures of an oil and gas property under previous Canadian GAAP are credited to the full cost oil and natural gas pool without recognition of a gain or loss unless the divestiture results in a change to the depletion rate of 20 percent. Under IFRS, divestitures of an oil and gas property will generally result in a gain or loss recognized in the statement of operations.

#### Impairment:

Under IFRS, producing and development assets are grouped into CGU's based on their ability to generate cash inflows independent from other assets or groups of assets. Impairment must be calculated at the CGU level, instead of the country cost center used under former Canadian GAAP, and is recognized if the carrying value of a CGU exceeds the greater of its value in use or fair market value less costs to sell. Assets are assessed for impairment when indicators suggest the possibility of impairment and at least at the end of each reporting period. Impairment losses are reversed when there is an increase in the recoverable amount.

### **Share-based Payments:**

Both previous Canadian GAAP and IFRS use the fair value method for accounting purposes. Under Canadian GAAP, share based expense was recognized on a straight line basis. IFRS requires the Company to estimate the number of options expected to vest when a grant of equity instruments do not vest immediately. In addition, each vesting installment is to be treated as a separate arrangement. Share-based payments are expensed using graded vesting and based on the estimated number of options expected to vest (forfeitures are estimated). Graded vesting will result in a greater portion of the compensation expense to be recognized sooner.

## **Decommissioning Obligations:**

Under previous Canadian GAAP, the discount rate is the credit adjusted risk-free rate. Under Canadian GAAP, any change in the discount rate is applied to the prospective additions to the obligation. IFRS uses the risk-free rate. Under IFRS any change in the discount rate must be applied to the entire obligation liability. IFRS 1 requires that an entity adopting the full cost accounting deemed cost exemption must also measure the decommissioning liability associated with property, plant and equipment as at the date of transition to IFRS with any impact recorded to deficit on adoption.

#### Flow-Through Shares:

Under previous Canadian GAAP, the obligation to incur qualifying expenditures from the issuance of flow-through shares is a disclosure item and the future tax liability associated with the renouncement of tax deductions from the issuance of flow-through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the premium received on the flow-through shares, being the difference in price over a common share with no tax attributes, is recognized on the statement of financial position. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized through profit and loss along with a pro-rata portion of the deferred premium.

#### **Deferred Taxes:**

Under previous Canadian GAAP, deferred tax assets and liabilities were presented according to the classification of the underlying asset or liability that created the difference in the deferred tax amount. Under IFRS, all deferred tax assets and liabilities are classified as long-term.

## Impact of IFRS on Financial Position and Results of Operations

#### Reconciliation from Canadian GAAP to IFRS:

The adoption of IFRS required the application of IFRS 1. IFRS 1 generally requires that an entity retrospectively apply all IFRS effective at the end of its first IFRS reporting period; however IFRS 1 provided certain mandatory exceptions and permitted limited optional exemptions. Certain IFRS 1 optional exemptions have been applied including:

- Deemed cost exemption for full cost oil and gas entities whereby exploration and evaluation assets were
  classified from the full cost pool to intangible exploration assets at the amount that was recorded under
  previous GAAP and the remaining full cost pool was allocated to the development assets and components
  pro rata using proved and probable reserve volumes.
- Decommissioning obligations exemption that allows any changes in decommissioning obligations on transition to IFRS to be adjusted through opening deficit.
- Share-based compensation exemption that allows a company to only have to evaluate share based compensation awards that were unvested as of the date of transition and that were issued subsequent to November 7, 2002.
- Business combinations exemption that allows a company to not have to restate any business combinations that occurred prior to the date of transition.
- Cumulative translation option that allows losses to be reset to zero with the adjustment going through opening deficit.

The accounting policies in note 3 have been applied in preparing the consolidated financial statements for the year ended December 31, 2011 and the comparative information as at and for the year ended December 31, 2010, the financial statements for the year ended December 31, 2010 and the preparation of the opening IFRS balance sheet at January 1, 2010, the Company's date of transition to IFRS.

In preparing its opening IFRS statement of financial position and comparative information for the year ended December 31, 2010, the Company adjusted amounts previously reported in financial statements prepared in accordance with former Canadian GAAP. An explanation of how the transition from former Canadian GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

	Canadian		transition	
	Note	GAAP	to IFRS	IFRS
Assets				
Current assets:  Cash and cash equivalents	\$	1,325,915 \$		\$ 1,325,915
·	Ş		-	
Accounts receivable		6,470,045	-	6,470,045
Prepaid expenses and deposits		532,808	-	532,808
Risk management contracts		126,749	-	126,749
		8,455,517	-	8,455,517
Reclamation deposit		157,650	-	157,650
Property, plant and equipment	С	108,267,249	(30,277,524)	77,989,725
Deferred taxes	Α	-	1,775,276	1,775,276
	\$	116,880,416 \$	(28,502,248)	\$ 88,378,168
Liabilities				
Current liabilities:				
Accounts payable and accrued liabilities		\$ 14,778,189	\$ -	\$ 14,778,189
Bank loan		22,290,000	-	22,290,000
Deferred taxes	A	36,757	-	(36,757)
		37,104,946	(36,757)	37,068,189
Flow through share premium	F	-	346,492	346,492
Risk management contracts		123,371	, -	123,371
Deferred taxes	A,C,E,F	7,860,589	(7,860,589)	-
Decommissioning obligations	Ε	14,044,639	7,137,490	21,182,129
. 00		59,133,545	(413,364)	58,720,181
Shareholders' Equity				
Common shares	F	100,955,986	5,515,697	106,471,683
Contributed surplus	G	5,980,601	189,946	6,170,547
Accumulated other comphrehensive loss	J	(507,506)	507,506	0,170,347
Deficit	A,C,E,I	(48,682,210)	(34,302,033)	(82,984,243)
Denoit	۸,۵,۱	57,746,871	(28,088,884)	29,657,987
			(=5,555,554)	
		\$116,880,416	\$(28,502,248)	\$ 88,378,168

		Effect of		
		Canadian	transition	
	Note	GAAP	to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		\$ 1,448,009	\$ -	\$ 1,448,009
Accounts receivable		8,099,902	- ب	8,099,902
Prepaid expenses and deposits		398,009	-	398,009
Deferred taxes	А	288,069	(288,069)	398,009
Deferred taxes	A	10,233,989	(288,069)	9,945,920
		10,255,969	(200,009)	9,945,920
Reclamation deposit		149,190	-	149,190
Exploration and evaluation assets	В	-	6,394,505	6,394,505
Property, plant and equipment	B,C	103,229,339	(28,898,313)	74,331,026
Deferred taxes	Α	-	1,775,276	1,775,276
		\$113,612,518	\$ (21,016,601)	\$ 92,595,917
Liabilities				
Current liabilities:				
Accounts payable and accrued liabilities		\$ 17,320,820	\$ -	\$ 17,320,820
Bank loan		11,412,875	-	11,412,875
Risk management contracts		993,344	-	993,344
		29,727,039	-	29,727,039
Flow through share premium	F	_	792,968	792,968
Risk management contract	ļ	427,169	732,300	427,169
Deferred taxes	A,C,E,F	4,071,145	(2,597,469)	1,473,676
Decommissioning obligations	A,C,L,I E	12,465,634	7,201,697	19,667,331
Decommissioning obligations		46,690,987	5,397,196	52,088,183
Shareholders' Equity				
Common shares	F	117,126,441	5,482,797	122,609,238
Contributed surplus	G	6,905,561	468,493	7,374,054
Accumulated other comphrehensive loss	I	(753,184)	553,188	(199,996)
Deficit	A,C,E,I	(56,357,287)	(32,918,275)	(89,275,562)
	. , ,	66,921,531	(26,413,797)	40,507,734
		Ć442 C42 E42	¢/24.046.604\	ć 02 F0F 047
		\$113,612,518	\$(21,016,601)	\$ 92,595,917

Reconciliation of consolidated statement of loss and comprehensive loss for the year ended December 31, 2010:

			Effect of	
		Canadian	transition	
	Notes	GAAP	to IFRS	IFRS
Revenues:				
Oil and natural gas revenue		\$ 43,665,720	\$ -	\$ 43,665,720
Royalties		(7,826,810)	-	(7,826,810)
,		35,838,910	-	35,838,910
Realized gain on risk				
management contracts		1,788,624	-	1,788,624
Unrealized (loss) on risk		,,		,,
management contracts		(1,423,891)	-	(1,423,891)
Other income		19,507	-	19,507
		36,223,150	-	36,223,150
Expenses:				
Operating	С	14,042,198	423,135	1,465,333
Transportation	-	819,054	-	819,054
General and administrative		3,586,124	-	3,586,124
Exploration and evaluation	С	, , , <u>-</u>	2,250,984	2,250,984
Property, plant and equipment				
impairment	С	-	5,948,300	5,948,300
Gain on divestitures	Н	-	(1,282,406)	(1,282,406)
Depletion and depreciation	C,D	28,581,552	(15,738,167)	12,843,385
Share-based compensation	G	817,239	233,588	1,050,827
Foreign exchange (gain)		(13,828)	-	(13,828)
		47,832,339	(8,164,566)	39,667,773
Finance expenses	E	1,019,755	756,042	1,775,797
Loss before tax		(12,628,944)	(7,408,524)	(5,220,420)
Deferred tax (benefit)	C,E,F	(4,953,867)	6,024,766	1,070,899
Net loss for the period		\$ (7,675,077)	\$ 1,383,758	\$ (6,291,319)
Translation loss on foreign operations		(245,678)	45,682	(199,996)
Net loss and comprehensive loss	\$	(7,920,755)	\$ 1,429,440	\$ (6,491,315)
Loss per share:				
Basic	\$ \$	(0.06)		\$ (0.05)
Basic				

#### Impact of transition to IFRS and 2010 results

- (A) Under IFRS, all deferred tax assets and liabilities are classified as long-term. Under previous GAAP, deferred tax assets and liabilities were presented according to the classification of the underlying asset or liability that created the difference in the deferred tax amount. The related income tax effect of the below noted adjustments have also been reflected in these statements
- (B) Exploration and Evaluation assets ("E&E") As required under IFRS 6, Arsenal reclassified \$6.4 million from Property, Plant and Equipment ("PP&E") to E&E at December 31, 2010. No costs were reclassified upon transition.
- (C) Under IFRS, impairment tests for PP&E are performed at a CGU level as opposed to the entire Company's PP&E balance being subjected to a full cost ceiling test under previous GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using the greater of the fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs, and the value in use. Upon transition to IFRS, Arsenal recognized a \$30.3 million impairment which was charged to the opening deficit. As a result of decreased forward natural gas prices and a downward revision of reserves in a certain CGU, Arsenal recognized a \$5.9 million impairment for the year ended December 31, 2010. This resulted in a reduction of PP&E with the offset charged to property, plant and equipment impairment.

Upon transition to IFRS Arsenal has also chosen to expense all dry holes, seismic expenditures and lease rentals. This resulted in \$2.2 million of dry holes and seismic expenditures being charged to exploration and evaluation expenditures in 2010 and \$423,135 of lease rentals being charged to operating expenses in 2010.

- (D) Depletion and depreciation expense Under IFRS, Arsenal has chosen to calculate depletion expense based on proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately \$15.7 million in 2010.
- (E) Decommissioning obligations Under previous GAAP, Arsenal's decommissioning obligations were discounted based on a credit adjusted risk-free rate of 8% at December 31, 2009. Under IFRS, the Company is required to revalue its obligation at each balance sheet date using a current liability-specific discount rate. At transition, Arsenal revalued the obligation based on a risk-free rate of 4% resulting in a \$7.1 million increase to the liability with the offset charged to deficit. A further change in the discount rate at September 30, 2010 resulted in a revaluation to increase the liability by \$1.1 million. As a result of the change in the discount rate applied, accretion of decommissioning obligation expense decreased by \$270,045 for the year ended December 31, 2010.
- (F) Under previous GAAP, the deferred tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the deferred tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a deferred tax expense as the expenditures are incurred. This deferred tax expense represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment resulted in an increase of \$5.5 million (December 31, 2010 \$ 6.4 million) to share capital with a resulting offset being charged to deficit.

For the year ended December 31, 2010, a deferred tax expense of \$1.1 million was recognized as a result of changes in the temporary difference between the net book value and the tax basis of the assets and liabilities.

- (G) Under previous GAAP, Arsenal expensed share-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Arsenal also incorporated a forfeiture multiplier rather than accounting for forfeitures as they occur as currently practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of \$189,946 with the offset being charged to deficit. This resulted in a \$233,588 increase to share-based compensation expense for the year ended December 31, 2010.
- (H) Divestitures Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case, a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed of.
  - For the year ended December 31, 2010, the Company recorded a \$1.3 million gain on disposition of oil and gas properties for IFRS as compared to nil under previous GAAP. During the third quarter of 2010, the Company disposed of certain properties with a combined net book value of \$6.8 million.
- (I) Cumulative translation losses Upon transition to IFRS, Arsenal elected to reset cumulative translation losses to zero with the adjustment going through opening deficit.

#### **Future Accounting Pronouncements**

The Company has reviewed the following new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company's financial statements:

(a) IFRS-9 Financial Instruments:

As of January 1, 2013, the Company will be required to adopt IFRS-9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS -39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete.

- (b) In May, 2011, the IASB released the following new standards which are effective for fiscal years beginning January 1, 2013 with earlier adoption permitted.
  - (i) IFRS-10 Consolidated Financial Statements, supersedes IAS -27 Consolidation and Separate Financial Statements and SIC -12 Consolidation Special Purpose Entities. This standard provides a single model to be applied in control analysis for all investees including special purpose entities.
  - (ii) IFRS-11 Joint Arrangements, divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting.
  - (i) IFRS-12 Disclosures of Interests in Other Entities combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.
  - (ii) IFRS-13 Fair Value Measurement, defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Company is currently assessing the expected impact, if any, that the adoption of these standards will have on its financial statements.

#### **Disclosure Controls and Procedures**

The Company has established disclosure controls and procedures for the timely and accurate preparation of financial and other reports. Disclosure controls and procedures are designed to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the periods specified by applicable securities regulations and that information required to be disclosed is accumulated and communicated to the appropriate members of management and properly reflected in the Company's filings. Consistent with the concept of reasonable assurance, the Company recognizes that the relative cost of maintaining these disclosure controls and procedures should not exceed their expected benefits. As such, the Company's disclosure controls and procedures can only provide reasonable assurance, and not absolute assurance, that the objectives of such controls and procedures are met. The Chief Executive Officer and the Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective in providing reasonable assurance that material information required to be disclosed by the Company in reports filed with Canadian securities regulators is accurate and complete and filed within the periods required due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and the Chief Financial Officer have individually signed certifications to this effect. There were no changes during the year ended December 31, 2011 in disclosure controls and procedures.

#### **Internal Controls over Financial Reporting**

The Chief Executive Officer and Chief Financial Officer of Arsenal are responsible for designing internal controls over financial reporting or causing them to be designed and their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Arsenal's management has assessed the design of internal controls over financial reporting.

While Arsenal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design assessment certain material weaknesses in internal controls over financial reporting were identified, as follows:

- Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs associated with such increase;
- Many of Arsenal's information systems are subject to general control deficiencies including a lack of effective controls over spreadsheets, access and documentation. The Company expects that these deficiencies will continue into the future; and
- Arsenal does not have full-time in-house personnel to address all complex and non-routine financial and tax issues that may arise. It is not deemed as economically feasible at this time to have such personnel. Arsenal relies on external experts for review and advice on complicated financial and tax issues and for tax planning, tax provision and compilation of corporate tax returns.

These weaknesses in internal controls over financial reporting result in a more than remote likelihood that a material misstatement would not be prevented or detected. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board do not have reasonable

assurance that this risk can be reduced to a remote likelihood of a material misstatement. There were no changes during the year ended December 31, 2011 to material weaknesses in internal controls over financial reporting.